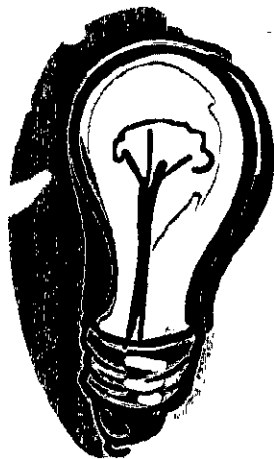


World Energy Council

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Electricity Market Design and Creation in Asia Pacific



May 2001

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Steering Committee

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China	Yu Weiguo	State Power Corporation
Hong Kong, China	Stephen Lau	CLP Power
Indonesia	Bambang Ali Winarso	Department of Mines and Energy
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Philippines	Francisco Viray	Philippine Investment Management Consultants
	Danilo Mercado	National Power Corp
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Taiwan, China	Jennifer Chen	Taiwan Power Company
Thailand	Sitthiporn Ratanopas	Electricity Generating Authority of Thailand
	Surapon Soponkanaporn	Metropolitan Electricity Authority
	Numchai Lowatanatrakul	Provincial Electricity Authority

The Steering Committee was supported by:

Administration	Vimla Mulchand	WEC Singapore
Study Coordinator	Graham Thomas	GT Power Consultants Ltd

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FOREWORD

When WEC's Asia Pacific regional members met in 1999, they agreed that the financial crisis in Asia of 1997 had made the issue of electricity market reform more not less critical. The question was: what market reform was appropriate? As this report states: "The 1990s were dominated by the search for competitive solutions, often without much understanding of the total costs and benefits of change. Benefits can be delivered, but the costs have been unexpectedly high, billions of US dollars per annum in some cases such as the UK and California. With hindsight, it is likely that most markets could have delivered the same benefits at a fraction of the costs."

WEC's Asia Pacific members were keen to learn all the possible lessons concerning, for example, the prioritisation of objectives, the matching of design to objectives and circumstances, where, when and how competition can be most effectively introduced, what role regulation should still play, the cost-benefit analysis of different design features and the trade offs between competition in generation and competition to create capacity, and between asset value maximisation and lower electricity prices for consumers. Key conclusions are that cost-benefit analysis against carefully prioritised objectives must be rigorous and the simplest model possible that will achieve the objectives should be used.

While the study was undertaken for the Asia Pacific and focused on those markets, its insights and conclusions are of far wider relevance. For developing countries electricity is a vital input for economic growth. In industrialised countries quality and cost of electricity supply becomes ever more critical in the electronic age. The stakes are high, both in terms of the rewards of well-designed reform and the penalties of badly designed or implemented reform.

In its Millennium Statement, *Energy for Tomorrow's World – Acting Now!*, the World Energy Council called for market reform with appropriate regulation. In probing the ways in which competitive pressures may be blended with regulation to simplify market design, this study makes an important contribution to achieving this objective. Above all, it demonstrates that the task of market reform is much broader than the creation of arrangements for competition in electricity generation, on which attention has so often been focused.

The WEC and its Asia Pacific members are especially indebted to Dr Graham Thomas, the Study Coordinator for the project. He brought enormous practical experience of the electricity markets of the UK and other countries to bear on the task. We extend our thanks equally to Mr Robert Pritchard, Chair of the Steering Committee, the Steering Committee members listed overleaf, and Jan Murray, WEC Deputy Secretary General, who leads WEC's Regional Programme, for guiding and participating in the work.

Antonio del Rosario

*Vice Chair for Asia and Chair Elect,
World Energy Council*

EXECUTIVE SUMMARY

In 1999, WEC's Asia Pacific members identified electricity market reform as a priority issue for their regional work programme. In particular, in embarking on their own market reform programmes, they wanted to learn the lessons of experience elsewhere. Accordingly the project, of which this report is the outcome, was launched. The work was guided by a Steering Committee drawn from the nine interested Asia Pacific countries and areas and coordinated by Dr Graham Thomas, initially seconded by PowerGen of the UK, but working as an independent consultant from 2000. Together they drew up terms of reference and a questionnaire to gather the necessary information. In the course of three workshops they reviewed this information, identified and prioritised reform objectives, examined experience elsewhere, analysed the conditions in which the objectives are likely to be realised and drew conclusions about appropriate electricity market design for the electricity industries covered by the project.

Market Reform Objectives

Eight priority market reform objectives were selected by the Steering Committee as the principal focus for the project.

1. To introduce competition in generation

Most electricity market reform has concentrated on creating competition in generation and this was voted the highest priority objective for reform. Its successful introduction, however, requires that there be:

1. Excess generation capacity of between 20–25% – competitive pressures depend on the possibility of a generator not being able to operate for the bidding period concerned.
2. An attractive investment environment – as competition in generation depends on having ample generating capacity, the investment to create it is a base condition of competition.
3. High current prices in generation and supply – if prices are already close to cost, the introduction of competition, which itself has a cost, is unlikely to be cost-beneficial.
4. The will to lower electricity prices – if, to the contrary, there is a need for steady or higher prices to pay off debt or add to capacity, then there are simpler ways of achieving the desired price profile.
5. Easy access to the grid – contracts for transmission must not present a barrier.
6. A well connected grid – transmission constraints will give rise to different competitive zones with those generators sheltered by a constraint able to demand higher prices.
7. Many competing generators – while the exact number depends on the similarity of the generating plant, excess capacity must be greater than the each of the generating companies. With plants with similar cost structure, five competitors may be sufficient, but with dissimilar plant ideally no company should represent more than 10% of the total capacity. Since price setting occurs throughout the full demand range, there need to be competitors at every demand level.

Absent even one item on this checklist, full competition in generation will not be possible, albeit it may be possible to introduce certain competitive pressures.

Especially in the absence of excess generating capacity, creating competition to construct additional capacity may be more urgent than creating competition in generation. Moreover, competition in generation will compromise competition to construct capacity.

2. To introduce customer choice

Although the expected benefits are lower electricity prices and better service, few markets provide choice for all customers. As distribution networks are normally monopolistic, the introduction of customer choice necessitates unbundling retail electricity suppliers (of the kilowatts) from physical distribution (their transport). Competitive supply then becomes a low margin business in which economies of scale may be obtained by spreading costs across several products with similar metering and billing requirements. In this situation, as few as five suppliers may provide real competition.

Where customer choice requires new metering, the costs are high, so customers should be segmented by consumption levels, with customer choice only extended to the smallest customers where it is supported by cost benefit analysis. The simplest approach to providing customer choice in a well connected market is simply to introduce primary legislation to dismantle monopoly supply areas and open up transmission and distribution to competing suppliers, as happened in Germany.

Fear of losing customers may be sufficient to raise service standards. To persuade customers to take advantage of choice, the costs to change supplier should be less than the anticipated benefit and the lead time allowed must accommodate the time needed to evaluate and implement a change of supplier.

3. To deal with stranded costs

Costs which could be recovered under pre-reform conditions, may not be recoverable following market reform, most often because higher cost of capital requires a shorter pay-back period. Arrangements to deal with such costs will distort competition, but should not do so to the extent that its benefits are lost. The options for dealing with the stranded costs of government-owned entities are wider than those for privately owned companies. In the latter case, successful negotiation of a solution calls for agreement on:

1. Market forecast assumptions;
2. Electricity and fuel prices;
3. The cost recovery package (which may include the selling off of some assets);
4. The future direction of market reform, if any.

Either way a levy applied to the price of electricity will be better accepted where the advent of competition leads to a fall in prices greater than the levy (as happened in the UK, but not California). Where stranded costs mean future electricity prices will rise, customers may prefer to continue with a regulated market for a further period, in which case they have exercised customer choice.

A stranded cost arrangement, like a long-term contract, can be used as security for borrowing, and has made it possible for some utilities to become cash-rich.

4. To attract private investment

The proof that a market is attractive to investors is that sufficient generation capacity is commissioned to meet demand in a timely fashion. With the high debt levels typifying generating plant construction projects (around 70%), stability of industry policy and regulatory regime and the ability to repay debt are crucial to investors.

The prospect of competition in generation being introduced will normally not be attractive to investors, particularly if there is excess capacity, though prior announcement and trialling of the proposed reforms in detail may help to overcome this problem. The availability of a fuel or technology which is cheaper than the existing capacity (as happened with gas in several markets) will also help. Alternatively, if a competitive generation market is to be introduced, security to attract investors in capacity may be offered in the form of long-term contracts or stranded cost arrangements. There are many opportunities for investment worldwide and, provided that access to the market can be achieved, investors do not themselves seek competition! Moreover, the lower the rates of return, the greater the certainty that investors will seek.

For a market to be attractive to investors, there should ideally be:

1. Clear demand for additional baseload capacity;
2. Government and regulatory stability for at least 2–3 years and ideally 5–10;
3. Efficient handling of tender applications, and the associated planning, environmental and connection applications;
4. Market change subjected to constraints and clear arbitration;
5. Transparent unbiased despatch rules;
6. Clearly announced rules for departure from economic merit order despatch;
7. Government ownership of no more than 20% of plant, as this need not operate to the same commercial imperatives and, in any case, has a lower cost of capital.

Changes introduced by governments subsequent to investment (for example, the UK's windfall tax of 1997) undermine investor willingness to re-invest.

5. To maximise asset value

Where market reform involves the selling of state owned assets, there is pressure to maximise asset values, both because taxpayers demand it, but often as a key element in paying off debt. As with attracting investment to new generating plant, however, asset sale values will be compromised by the prospect of competition in generation being introduced. In some early privatisations (for example, Victoria in Australia), high prices were paid for plants before it was appreciated how much subsequent competition in generation would depress plant revenue. A valid strategy for governments remains to down play plans to introduce competition in generation until assets have been sold, thus maximising values, and then to introduce an electricity market to lower prices for the electorate. Other ways in which asset value can be boosted include understating plant operating cost, inconsistent power purchase agreements or using government owned plant to lower prices. Investors have become more wary, however – caveat emptor!

In any case if generation and transmission assets are to be sold separately, unbundling of these two sectors should already have occurred, as generation plant

value will depend on future electricity prices and transmission system value on transmission charges.

6. To entrench universal service agreements

Electricity has become such a vital service, that the goal of most societies is to provide universal access. Some customers will not be economic to supply under competitive conditions and universal access can only be achieved by modifying the market in one way or another. Either they can be supplied on a regulated cost plus basis or they can be cross-subsidised in a standard tariffs market. If the former, the government should have a clear investment plan to deal with non-economic customers. If the latter, the cross-subsidy should be transparent. Either way, tendering can be used to establish a market price for supplying the service, though the service itself would be supplied on a monopoly basis at least initially.

7. To promote integration of the grid

New transmission line should be built if its construction and maintenance costs are less than the additional (out of merit order) generation costs caused by the constraint that is removed. In vertically integrated utilities, it could be expected that this calculation would be made. Where generation is separated from transmission, the position is more complicated. As transmission is a cost plus regulated monopoly, transmission companies will tend to build transmission lines as it adds to the asset base on which their revenues are calculated. The need for new transmission line can still be tested by how low a price a generator is prepared to bid to avoid its construction.

Interconnection of two grids with differing price levels presents a particular difficulty as the price in the lower priced market should rise. Charges, despatch and bidding rules should be settled in advance to establish the project value. There should also be an independent despatcher and reciprocal access between the markets.

With large grids, the modelling of transmission costs and losses should reflect reality to the extent possible and should be reflected in the transmission charge, so as to discourage trading not warranted by competitive costs. Experience suggests that the market size of one despatch area is approximately 200–300 TWh annual volume and a distance of 700 km though interconnections may be made over longer distances for security of supply reasons.

8. To reduce debt

Debt reduction is often achieved from asset sales in initial privatisations and the considerations of asset value maximisation apply. Otherwise, debt can be reduced through achieving an increased margin between electricity prices and costs, or in other words electricity prices must be higher than they would be without the debt reduction. Levies to reduce debt also translate into the electricity price and are subject to the same considerations as those to deal with stranded costs.

Issues With the Most Financial Impact

Reflecting the importance attached to the cost-benefit of market reform, the Study Coordinator identified the 10 issues which, in his view, have the greatest financial impact. They tended to reflect a greater emphasis on external factors.

The principal change of priorities compared with those established by the Steering Committee for market reform objectives was to give the national environment for private investment first priority. As competition in generation is not possible without excess capacity, and as most Asia Pacific countries have relatively high rates of growth in electricity demand, the starting point must be attracting the investment to create the necessary excess capacity. Failure to add sufficient capacity can become a critical constraint on GDP growth and thus has nationwide implications.

A second issue, which gained in importance when ranked for its potential financial impact, was the rate selected for debt reduction. If this rate is set so that debt reduction measures represent a significant element of electricity prices, it is better simply to set these high prices through regulation than to introduce competition.

Additional issues included by the Study Coordinator on the basis of financial impact were the balance between government, regulator, and industry, the existence of a national energy strategy and solutions for certain social issues:

- The greater the unilateral power of the regulator, the greater also the investor's risk, although a trend to tighter regulation, or re-regulation, is observed. The investor's prime requirement is stability, which can be compatible with tight regulation, but investors also seek some influence over regulatory changes.
- Countries need to secure a suitable energy mix over timeframes of 20–30 years. An energy policy at variance with short-term market outcomes for some reason (for example, fuel security, environment, employment or dealing with stranded investment) is incompatible with full competition.
- In addition to non-economic customers who may not receive service under market conditions, there can be other social impacts, such as the loss of competitiveness of an indigenous fuel industry (typically coal displaced by gas) or unemployment caused by increased power system automation, itself a response to competitive conditions. Market modifying measures can be introduced to reduce the impact of these problems if it is so wished.

Market Design Options

In determining market design, the competitive potential of the whole electricity chain must be examined:

- Fuel supply – there should be diversity of fuel and several suppliers for each fuel;
- Generating capacity construction – there should be at least three competing bids;
- Generation operation/despatch – the most widespread focus of market reform;
- Transmission – competition to construct transmission is possible, but not to operate it, so it may remain under state ownership or be tightly regulated;
- Distribution – similar considerations as for transmission;
- Customer supply and/or services – can be competitive where unbundled from distribution.

While recognising this broader scope of electricity market design, the report focuses on competition to construct generating plant and competition to operate generating plant.

1. Competition to construct generating plant

Three broad options, or models, are available:

1. Central planning – the state utility or government plans future capacity and the competitive element can be tenders to construct or to construct, own and operate. The management of social issues and fuel diversity is simplified – the risk is bureaucracy.
2. Constructor's free choice – both fuel and technology is chosen by the constructor. The output can be sold to a central purchasing agency, direct to the customer, or a pool.
3. Hybrid – there is a plan and tenders to fulfil it as in 1 above, but also no restriction on other plant being built. Where investor interest is inadequate to fulfil the plan, the state commissions the plant, ensuring that there is always the planned capacity.

2. Competition to operate generation plant

Two broad approaches are now in use to create competition in generation, a mandatory pool for all electricity generated and a contracts market with a balancing pool. A trend towards the latter is discernible. Although the two models vary in detail in different countries, it is more their introduction into very different circumstances and industry structures that explains the varying outcomes.

Under either approach, despatch and price setting should be considered independently. The purpose of despatch is to meet demand within the set stability and frequency parameters, taking into account transmission constraints. The information needed is plant availability, the technical parameters of plant and transmission system, costs to determine a basic merit order and non merit order requirements. Although despatch clearly needs to be done in real time, the information does not change frequently and relatively simple information systems can be used. Even where costs tend to be quite stable, price volatility is more often due to market opportunities than changes in underlying costs.

Frequent price setting adds greatly to complexity, especially in terms of the information systems needed and new metering. Representing the UK electricity market, for example, is more complex than the whole London Stock Exchange trading and settlement system. Unless there are commensurate benefits, the cost cannot be justified. Typically only some 5% of customers can respond to short-term price signals. Special arrangements can be made for this 5% without burdening the whole market with the complexity of real time or short interval pricing. In addition, longer bidding periods add to the competitive pressure on generators. If the bidding period is a season or year, the risk is high and the incentive to bid prices close to costs is also high. With half hour or daily bids, a generator can always hope to operate in the near future. Longer timeframes may also allow existing metering to be used. For all these reasons, there is great value in using the longest pricing period that reflects underlying changes in costs, for example, seasonal. Even imbalances markets can operate on longer time intervals.

Five basic models for generation markets were identified for consideration:

1. Pool with system marginal price – was the first to be used (in England & Wales, Victoria and New South Wales), with variations, in electricity market reform. Generators and some or all wholesale suppliers bid into the pool. Sometimes a capacity element is included.

2. Pool with pay-as-bid price – is similar to most “outcry” commodity markets but has not actually been used. Generators would be paid as they bid, encouraging them to compete to set prices through the price curve.
3. Contracts with despatch priority and system balancing – became more popular in the late 1990s, and now being adopted in England & Wales. Competition is more aggressive than in mandatory pools as a physical contract must be won in order for plant to be despatched. Various approaches are possible to avoid complexity in the balancing market.
4. Minimalist model – customer choice is introduced, as in Germany, through primary legislation, without any central settlement system being developed. This is effective in a well connected market with a large number of generators.
5. Simple central market – would be operated by a, preferably independent, system operator, who would verify input costs and contract terms.

Key Conclusions

- The introduction of competition into electricity markets can deliver real benefits in terms of cost efficiency, downward pressure on prices and customer focus, but the costs of market introduction can be high.
- It is necessary to undertake rigorous cost-benefit analysis of intended market measures to ensure that benefits are commensurate with costs.
- The competitive potential of each stage of the electricity chain should be examined when designing an appropriate market, not just electricity generation.
- Competition at one stage, for example, competition in generation, may compromise objectives at another, for example, competition to construct capacity.
- Similarly, the introduction of competition in generation will lower asset sale values and the ability to repay debt.
- Market modifications will be needed to achieve social and national goals (pure competition and energy policy are likely to be incompatible).
- The simplest approach should be used that will achieve the desired benefits to a reasonable degree – keep it simple!
- If competition in generation is appropriate, separate despatch from pricing, so that longer time frames may be used for pricing, with benefits in terms of reduced cost and increased competitive pressure.
- A blend of market and regulated features is likely to simplify market reform in many circumstances and to deliver similar benefits to more complex market designs.

1. MARKET REFORM OBJECTIVES, CRITERIA AND ISSUES

1.1 Background to the Study

In May 1999 the WEC Asia Pacific member committees met in Manila to assess the critical energy issues facing the region and to determine a plan of action. Getting electricity market reform right was seen as one of the most important of these issues. Accordingly it was agreed to study specific electricity trading arrangements to draw market design lessons for those in the Asia Pacific region now considering industry liberalisation and restructuring. The study would cover the trading arrangements employed in competitive electricity markets, including pools, power exchanges and contract trading. The meeting recognised that other aspects of liberalisation, such as re-structuring, privatisation and the regulation of market features and sectors, were also of relevance and could not be ignored.

Subsequently a Steering Committee was formed by interested WEC members to scope the project and develop terms of reference. The membership of the Steering Committee is given at the front of this report. The study was coordinated for WEC by Dr Graham Thomas, on full-time secondment from PowerGen of the UK until the end of 1999. After that date, Dr Thomas continued to coordinate the study on a part-time basis as an independent power consultant.

The first Steering Committee meeting was held in Hong Kong in July 1999. It was agreed that the purpose of the study was to provide information that would help each WEC member involved make the major decisions required over the next few years about its electricity industry and market. Every attendee identified the expected major changes in their electricity industry over the next five years or so and the objectives which these reforms were intended to meet.

With this collective information the Steering Committee was able to scope the study in terms of the information needed and the related actions. This included designing a questionnaire to be sent to WEC member committees, government departments, regulators, electricity exchanges and utilities. The Steering Committee also refined the terms of reference, which were reported back to the WEC Asia Pacific member committees for endorsement.

1.2 Terms of Reference

The main aims of the study were defined as:

1. To identify and report on the criteria that need to be considered in designing and creating competitive and efficient electricity markets in the Asia Pacific region.
2. To examine international experience to date, highlighting the need for clear policy objectives and a clear understanding of the risks. In this regard, subject to inputs received and limitations of time, analysis would include whether the original policy objectives had been achieved, whether there were any other significant advantages or disadvantages flowing from the market creation process, and the reasons for these outcomes.

3. To produce information that would enable governments and industry participants to understand better the potential impact of alternative structural and regulatory changes on domestic industries and future investment patterns.
4. A further aim was to provide WEC Asia Pacific member committees with a methodology which would enable members to feed in future experience to provide an ongoing and up-to-date source of information on international market reform.

1.3 Questionnaire

At its first meeting, each member of the Steering Committee was asked to identify the top three objectives, as they saw them, of their own electricity industry liberalisation programme. There was little common ground in these objectives, except at the most general level. As a consequence the questionnaire had to cover a wide range of topics.

The detailed questionnaire, given in Appendix 1, was developed primarily to try to determine the costs and benefits of liberalisation changes introduced in other electricity markets. To cover the ground identified by the Steering Committee, information was collected on the following areas:

- Objectives of liberalisation and current challenges.
- Government and regulatory powers.
- Market results and the level of satisfaction.
- Market operation and physical system operation.

This method of data collection could continue to be used to gather information periodically on the benefits resulting from the markets examined, a significant sub-purpose of the study (aim 4 above) being to assess the success of this form of data collection and analysis, so that it may be improved upon and repeated for future updates. At the time, few electricity markets had significant operational experience, and some which did (namely England & Wales, Australia and New Zealand) were represented in the Steering Committee.

Members of the Steering Committee were responsible for producing the questionnaire responses for the country or area which they represented. Details of recent industry history, government objectives, liberalisation proposals and current issues were obtained, to enable comparisons with information gathered from the more liberalised markets mentioned above. This information was summarised by the Study Coordinator, and is presented in Chapter 2 in a standardised format for ease of comparison. The same format was used by the Study Coordinator to capture the liberalisation history and the benefits and disadvantages of the England & Wales electricity pool (Appendix 2).

1.4 Liberalisation Objectives Selected by the Steering Committee

It is clear that the relevance of some aspects of electricity market reform extend well beyond the electricity sector. For example, much of the local environment for private investment is not specific to the electricity sector. The risk attached to a particular market, legal procedures and the consequent timescales for resolving contractual disputes (particularly with the government), and procedures for planning application approvals by national and local authorities are common to all

investment sectors. It may be such general issues that prevent adequate investment in the electricity sector and which need to be addressed before the introduction of an electricity market can deliver cost benefits.

The environment for private investment also has electricity-specific features, however, that can hinder investment, such as procedures for connection approvals to the grid, and the terms of a project's fuel, construction and power purchase contracts. Any one of these areas may be a barrier to new entrants. These difficulties are very common, particularly in those markets where liberalisation is relatively new. The problems are usually more numerous for the foreign investor than for domestic investors.

Accordingly it was recognised some of the issues (or some parts of them) were beyond the scope of the study. At a workshop held in Singapore in March 2000 the Steering Committee decided to focus on eight electricity-specific objectives, which were voted upon to rank them in order of highest priority. There was no clear consensus. The top four objectives all had at least one member who ranked them in the bottom two.

The objectives chosen by the workshop and their rankings are as follows:

Objective	Priority given by each member
1. To introduce competition in generation	(1,1,1,2,2,3,4,7)
2. To introduce customer choice	(1,1,2,2,2,6,7,8)
3. To deal with IPP/stranded cost issues	(1,1,2,4,4,4,8,8)
4. To attract private investment	(1,2,3,3,6,7,7,8)
5. To maximise asset value	(3,4,4,5,5,5,7,8)
6. To entrench universal service obligations	(3,5,5,5,6,6,8,8)
7. To promote integration of the grid	(2,3,6,6,7,8,8,8)
8. To reduce debt	(3,4,5,6,7,8,8,8)

These objectives are discussed in Chapter 3.

For each applicable objective it is necessary to develop one or more measurable criteria. These will be specific to the individual market, but the criteria must be self-consistent. To the extent possible, they should be quantifiable so that the success of any change introduced can be measured. As will be discussed below, the level of success should be measured in some form that compares the benefits with the cost of introduction. The criteria that can be used to establish the success of the liberalisation measures designed to address the eight objectives above are also developed in Chapter 3.

1.5 Issues Selected by the Study Coordinator for their Financial Impact

When a government proposes to liberalise and to introduce a market in an industry sector, such as electricity, both the internal and external issues need to be addressed. The decisions are taken mainly by internal parties, usually through the government, which has broader responsibility than the specific industry itself. In selecting their eight priority objectives, the Steering Committee members tended to emphasise the internal perspective. However, the sharing of issues within the Steering Group raised questions that encouraged the development of a stronger external perspective. Previous experience of investing abroad had a similar effect, as did experience of issues such as the use of imported fuel versus the

development of indigenous fuel sources in a market environment. In a few cases, the opportunity of exporting electricity to adjacent electricity markets also raised awareness of the external perspective and how markets may need to interact.

At the Singapore workshop the reports presented in Chapter 2 were used to produce a master list of the key issues that should be considered for all electricity markets covered by the study. This list was further developed by the Study Coordinator, with more focus on external influences, and then debated by the Steering Committee. Some of the issues identified by the Study Coordinator from the external perspective were not recognised by the participants as being among the top priority for resolution, demonstrating the difference in perspective that may arise when examining the same subject from different logical starting points.

A second important dimension is cost-benefit. The potential value of addressing the listed issues was therefore considered in financial terms, to enable relative savings and expenditure to be compared.

For example, the introduction of a market has an associated introduction cost and subsequent annual expenditure, and an expected benefit to be realised over future years. Financially, future benefit could have a lower priority than large savings or receipts that are realised very early. If the cost benefit of a particular design of market is to be compared with that of other designs, then it should also be compared for value against other approaches that can be introduced to address industry problems.

From the master list of issues, those which the Study Coordinator identified as having potentially the largest financial impact were in order of importance:

1. The local environment for private investment.
2. The balance of powers between government, regulator and industry.
3. Government investment strategy.
4. The rate of debt reduction.
5. The balance between the value of state assets and future electricity prices.
6. Recovery of stranded costs.
7. Finding solutions for related social issues.
8. Grid interconnection within the proposed market area.
9. Whether to use a regulated or competitive solution for each industry sector.
10. The form of competition in generation.

These issues are discussed in Chapter 4.

1.6 Possible Market Designs

One of the main purposes of the study was to investigate the success or failure of different aspects of electricity markets already in operation. As there are very few examples of markets that have developed beyond the introduction of competition in generation, the Singapore workshop agreed that this should be the main focus of the report when looking at possible market designs.

Electricity markets introduced during the 1990s have followed two basic designs. The first half of the decade was dominated by the pool design introduced by England & Wales in 1990. Pool competition focuses on short-term generation despatch and marginal price setting. The second half of the decade saw the focus move towards contracting and the introduction of power exchange trading, similar to systems used in more mature commodity markets. In such systems, short-term

plant despatch and pricing are determined by rules for the balancing market. The main features of this system were first introduced in Scandinavia, and were further developed in California.

In practice, therefore, comparisons are of very similar market models, but introduced into significantly different industry structures and circumstances. The study thus looked at circumstances that favour the delivery of benefits from competition, and at circumstances that impede competition. These factors and their influence on possible market designs are discussed in Chapter 5.

Clearly, both these basic designs can be problematic, depending upon individual industry and market factors. Both designs are also relatively complex, meaning that they require large financial and other resources, and that their introduction has a long timescale. Consequently, alternative industry reforms should be considered for delivering the desired benefits more efficiently.

In addition it is clear that some higher priority problems must be solved before a competitive market design can deliver benefits. Consequently, a logical conclusion from the study is that it can be premature or practically impossible for some market designs to deliver cost benefits in the foreseeable future. Here the foreseeable future may be considered to be at least 10 years, even though change can be achieved quickly under favourable circumstances.

These aspects of market design are also discussed in Chapter 5, which provides a generic study from which both positive and negative lessons may be drawn. Options for using combinations of competition and regulation are considered, to explore in particular how a market could remain relatively simple and yet still deliver the desired benefits.

An important message from the study is, therefore, that simple market features combined with appropriate regulation could probably have delivered more benefit to customers, in terms of lower prices and better standards in supply, than has been achieved in those markets about which information was gathered. Taken further, this message would imply that governments within the Asia Pacific region should consider simplification of market proposals where possible. In particular, the use of pricing based on longer time periods should be considered rather than real-time pricing.

1.7 Study Coordinator's Observations on Proposed Liberalisation Plans

The next and final step was then to compare the circumstances within the countries and areas represented on the Steering Committee with those expected to deliver benefits through competition in generation. The Study Coordinator's analysis and conclusions on each market's design criteria were presented and discussed at a further workshop held by the Steering Committee in Tokyo in October 2000 and are contained in Appendix 3.

Data tables for six of the markets covered are contained in Appendix 4.

2. STATUS OF ELECTRICITY INDUSTRIES REPRESENTED ON THE STEERING COMMITTEE

2.1 Australia

2.1.1 Background

Australia is a federation of sovereign states, which formed the Commonwealth of Australia in 1901. Today it consists of six states and two territories. Under the Australian Constitution, there is a division of powers between the Commonwealth and the states, analogous to that in the USA. Powers not specifically assigned by the states to the Commonwealth remain with the states (the so-called “residual powers”).

Thus although the Commonwealth government has power over energy imports and exports, constitutional responsibility for electricity and other fuels remains with the separate state governments. Consequently, the electricity supply industry in Australia is organised on a state basis. Apart from its involvement in the Snowy Mountains Hydroelectric Scheme (which supplies two states and one territory), the Commonwealth of Australia is not directly involved in electricity supply.

The population of Australia is highly urbanized and concentrated in a number of coastal state capitals at vast distances from each other. Historically there was little incentive to build costly transmission lines between these distant population centres. This tendency was reinforced by the existence in most states of local energy resources. The differing nature of these resources – brown and black coal, gas and hydro and the range of qualities of the coal resources – resulted over the years in significant differences in the cost of electricity between the states.

The organisation and ownership of the industry evolved as the systems became larger and as pressures grew for power generation facilities to increase in scale and be relocated away from the cities. Although privately owned power companies were common in the early part of the century, the tendency towards state ownership in Australia in the 1930–1950 period led to the virtual extinction of private power companies by the mid 1950s. The industry was then predominantly in government ownership for some 40 years. In some states, power could not be produced privately without the permission of the state authority.

Until the 1990s, the electricity utilities in each state generally consisted of various forms of statutory authority (organisations established by statute, with ownership vested in each state government). Their functions varied between complete vertical integration from fuel source to customer, integration of generation and transmission, or distribution only.

These statutory authorities typically paid no income tax, were exempt from other taxes and charges, and operated with a government guarantee against their borrowings, giving them access to lower cost debt financing than their private sector equivalents. On the other hand, they were subject to other non-taxation related financial imposts, were expected to perform community service obligations without additional payment, and were subject to differing degrees of control by the minister of the state governments.

The source of fuel was the most important determinant of the development and structure of the industry in Australia. Traditionally, oil and gas reserves were developed only by the private sector in Australia, coal reserves were developed by the electricity utilities in some states and by private companies in others, and hydro resources were developed virtually exclusively by governments, either through the electricity authorities or by separate water authorities.

Australia is blessed with abundant reserves of high grade, low cost coal, both black and brown. Sulphur contents are low by international standards (no coal used for power generation in Australia has a sulphur content exceeding 0.6%), and ash contents include some low values. Prevailing air emission standards can thus readily be met without requiring the installation of flue gas de-sulphurisation units.

Black coal is the dominant fuel in NSW and Queensland. Victoria's electricity supply is dominated by brown coal generation, while South Australia uses its lignite. Hydro electricity provides some 9% of electricity produced, and is dominant in the island state of Tasmania. Natural gas supplies about 5% of the total, and is especially important in South Australia and Western Australia. Coal nevertheless remains the predominant source of energy for power production in Australia, producing almost 85% of the public electricity supply.

Total electricity generation for Australia amounted to some 180 TWh in 1998/99, produced from an installed capacity of 39.3 GWe. The electricity supply industry employed some 33 000 people in that year and serviced the needs of 8.3 million customers. Total revenue was A\$12.9 billion, at an average tariff of 8.22 A¢/kWh sold. These figures correspond to US\$7.1 billion and 4.5 US¢/kWh at an exchange rate of 55 A¢/US\$. At these levels, Australian power prices tend to be in the lower quartile of international power tariffs reflecting, in particular, the low prevailing fuel costs available to the Australian utilities.

Steam turbine plants generate the bulk of the electricity produced, using unit sizes of up to 660 MWe in NSW, 500 MWe in Victoria, 350 MWe in Queensland, 250 MWe in South Australia and 300 MWe in Western Australia. These unit sizes are relatively large for the systems in which they exist. Tasmania's hydro units range up to 144 MWe installed, while on the mainland, the Snowy Mountains Hydroelectric Scheme has 3.8 GWe in units of up to 250 MWe in size. Mainland hydro schemes are usually designed for low operating load factors, due to limited water inflow regimes. The Snowy Scheme, for example, is designed for a 15% long-term capacity factor.

In most states, natural gas fired units are used for intermediate and peak load operation. In South Australia and Western Australia, natural gas is also used for base load operation. The Northern Territory has the only operating combined cycle power plant in Australia, with a second such station under construction in South Australia.

Load growth rates in Australia have been relatively high in recent years – around 5% per year. Future predictions tend to be around 3% per year, with higher growth rates expected in Queensland and Western Australia, driven by above-average increases in population in those states and by some large mineral processing projects which are planned.

The states' transmission systems utilise differing levels of high-voltage transmission capacity and are interconnected only in two cases. These are the link

between NSW and Victoria (at 330 kV via the Snowy Mountains Hydroelectric Scheme since 1959) and the link between Victoria and South Australia (at 500/275 kV to Victoria since 1989). Queensland operates a very long 275 kV system within its borders.

The NSW and Queensland electricity systems will also be connected in 2001, and an HVDC undersea link from Victoria to Tasmania is planned for about 2003–04. Further interconnections are unlikely, particularly to Western Australia and the Northern Territory, because of the long distances involved.

Historical Drivers for Change

Pressures on the industry to change intensified in the early 1990s. Electricity prices in Australia increased in real terms in the 1980s, due to over-investment in generating facilities (encouraged by the state governments in expectation of a “mineral boom” which did not eventuate) coupled with over-manning and relatively poor plant performance. A series of public inquiries in the various states in the mid 1980s cast doubt on the efficiency and productivity of the electricity supply industry in Australia and on the adequacy of its planning procedures.

In 1989, the Industries Assistance Commission (IAC), a Commonwealth government organisation, drew unfavourable comparisons between the productivity and economy of the industry, compared to best Australian practice, and against best international practice, claiming that well over A\$1 billion could be saved if the industry were to achieve best international practice.

The IAC also joined others in criticising the lack of planning coordination between the largest states, putting forward the concept of a national grid (at least for the east of Australia) to remedy the shortcomings. It particularly recommended strengthening interconnections between the state systems, as well as increased private sector participation and the provision of non-discriminatory access to the national grid by private sector competitors.

In May 1990, the Industry Commission (a reformed version of the IAC) commenced an in-depth inquiry into the generation, transmission and distribution of electricity and gas. In May 1991, it reported that: “there is substantial scope for improving the efficiency of energy generation and distribution in Australia. The potential gains are large – in the order of A\$2.4 billion a year.”

The report recommended extensive changes aimed at increasing competition and improving efficiency. These involved separating the ownership of generation, transmission and distribution, and progressively selling many of the publicly owned generation and distribution assets. It also recommended that transmission and distribution systems be open to access by third parties. It noted that its recommendations “would result in a considerable diminution in the dominant role traditionally played in Australia by publicly owned, vertically integrated utilities.”

In particular, the Commission strongly favoured the corporatisation of public utilities as a means by which gains could be captured relatively quickly.

The report also strongly favoured the provision of new capacity by the private sector and, in any event, came out in favour of all major new investments being subject to competitive tender, with evaluation of tenders being conducted by a neutral body.

Meanwhile, the Prime Minister of Australia initiated a series of special intergovernmental conferences, aimed at reviewing the whole range of federal/state relationships, with a view to rationalising differences between the states and eliminating inefficiencies and distortions. These conferences evolved into a formal arrangement known as the Council of Australian Governments (COAG).

At the first of the intergovernmental conferences, reform of the electricity industry was raised as an issue and a working group was set up to recommend the changes necessary to modernise and improve the performance of the industry. The report of the working group was presented at the July 1991 COAG conference.

Government Policy and Objectives

As part of the COAG Conference discussions in 1991, consideration was given to measures to improve the efficiency of government business enterprises generally. The guiding principles were corporatisation of government enterprises (whereby they would be organized on lines comparable to private sector companies with respect to arm's length management, tax, rates of return and accounting) and "competitive neutrality" (whereby corporatised enterprises should compete on equal terms with private sector companies in similar businesses). As part of the package, community services obligations were to be refunded by governments to corporatised entities.

The 1991 COAG conference also made major decisions on the future reform of the electricity supply industry in Australia. It declared that:

- Extensions to the existing interconnecting system were economically viable (possible extensions included the HVDC undersea link between Victoria and Tasmania and the interconnection between NSW and Queensland).
- A National Grid Management Council (NGMC) should be formed.

The key tasks for this NGMC were:

- To coordinate planning so that future increments of generation capacity would be decided on a competitive multi-state basis having due regard for key national and state policy objectives.
- To coordinate access to the grid for private generating companies, public utilities, and private and public electricity customers (the process for direct arrangements between major customers and generators was to be defined subsequently).
- To monitor the performance of the national grid on behalf of the governments.

In April 1995, the Commonwealth and state governments entered into a Competition Principles Agreement, in which each government agreed to implement a common competition policy in each jurisdiction. The policy elements included:

- Applying competitive neutrality principles to government and private entities operating in similar markets.
- Making structural changes to government business enterprises to separate regulatory activities from commercial functions and to isolate natural monopoly functions from potentially competitive functions.
- Introducing access regimes to facilitate third party access to all essential infrastructure facilities (not just in the electricity industry).

A National Competition Council was established with power to review progress in the states and to recommend levels of compensation to be paid by the Commonwealth to the states for the loss of state revenues from the application of the new policy. The level of this compensation was quite significant in relation to state budgets and it provided a real incentive for the states to cooperate.

Substantial amendments were also made to the Trade Practices Act, the major competition law in Australia, to allow the Australian Consumer and Competition Commission (ACCC) to establish a formal process for approval of access regimes.

Thus the moves to reform the electricity industry in Australia which had begun in the early 1990s became linked with an economy-wide move towards competition policy reform. The gains available from the reforms in electricity were always seen to be one of the major reasons for the wider policy reform and were in fact the major contributor towards the national efficiency benefits arising from the reforms.

2.1.2 Liberalisation Progress

Following the formation of the NGMC in 1991, Australia began an extended period of debate, consultation and consideration of the design of the proposed National Electricity Market (NEM) and its operating rules. With the introduction of the new competition policy in 1995, adjustments had to be made to conform to the new legal framework.

First, however, the various states trialled state-based markets. Victoria trialled a series of models (known as “VicPool”) from 1992, beginning with contract-based trading with access to an optional pool, and moving to a compulsory pool similar to the one which had begun operation in the UK in 1990. NSW separately trialled and then implemented its ELEX model, which also had similarities to the UK approach.

Victoria began operating its pool in 1995, and NSW began its separate pool in mid 1996. The two states soon agreed to “harmonise” their trading systems and, in early 1997, a transitional cross-border market commenced with South Australia participating as a member of the Victorian pool. In 1998, Queensland implemented a similar interim state market.

In 1996, the states agreed to form two new entities to be responsible for management of the new NEM. The first was an independent market and system operator, or ISO, known as the National Electricity Market Management Company (NEMMCO). The second was a rule-making entity known as the National Electricity Code Administrator (NECA).

These two management entities are corporations under Australian law, but are entirely owned by the state governments participating in the NEM. Thus the control of the state governments still extends to the control of the two institutions which operate the national market and administer the market rules.

NEMMCO is responsible for:

- registration of market participants;
- balancing power system supply and demand;
- power system security;
- spot market administration, pricing, metering and settlements;
- coordination of global power system planning with network system providers.

NECA is responsible for:

- monitoring and reporting compliance with the National Electricity Code;
- enforcing the code;
- resolution of disputes;
- managing changes to the code.

The NEM officially commenced on 13 December 1998 when the National Electricity Code came into force. This had the effect of abolishing the state markets.

After establishing the national wholesale market, each state began to introduce contestability in retail markets, phasing in with large customers and progressively allowing smaller customers to purchase electricity on a competitive basis. As at the end of 1999, customers consuming 160 MWh/year or more (typically around 50% of total demand) were contestable. Full retail contestability will prevail in most states by 2002–03.

Until competition is available to them, retail customers pay tariffs which are regulated by the relevant authority in each state.

Privatisation

Prior to the early 1990s, private ownership of electricity supply facilities in Australia was mainly confined to self-generation in remote areas and to special cases.

In the early 1980s, the Eraring Power Station in NSW had been sold to a private partnership, but the station remained essentially controlled by the state authority. The arrangements were driven by taxation and financing considerations and, as a result, the Commonwealth government amended the taxation law to prevent a repeat of this type of transaction.

Several small independent power projects (IPPs) were approved in NSW and Western Australia in the early 1990s.

Victoria. The state of Victoria led the move towards privatisation in Australia, driven by concern over mounting debt levels. In 1991, the Victorian Labor government decided to sell 40% of the partly completed Loy Yang B (2 x 500 MW) brown coal power station. The sale was supported by a power purchase agreement (PPA) with the state electricity utility, which underwrote the market risk (there then being no competitive market in which the purchaser could trade).

In late 1992, with a change of government in Victoria to the conservative coalition, the policy became one of aggressively breaking up the previous vertically integrated utility and privatising all elements of the industry. The incoming state government had become alarmed by mounting debt levels in the electricity industry and the state in general, as well as by high power costs and by very low productivity and plant availability. Electricity industry debt had by then reached A\$9.5 billion and total state debt had reached A\$32 billion.

The Victorian government first separated the functions of generation, transmission and distribution. It then established five generation corporations, one transmission corporation and five distribution/supply corporations. Initially these were government owned, but they were established with the clear intention of privatisation. During a period of five years between 1994 and 1999, the Victorian government sold off each of the generation, transmission and distribution entities,

for a total of almost A\$23 billion – a figure much above expectations at the time – placing the entire electricity industry in Victoria into private ownership.

By 2000, however, reflecting a worldwide tendency towards industry rationalisation and review of investment strategy, some of the distribution companies had been resold or had become available for sale and the transmission company had become available for sale. As well, some of the generators had written down the value of their assets, reflecting the lower levels of wholesale electricity prices which had been experienced since the original privatisations took place.

Other states. In late 1999 after a prolonged political debate, South Australia also began to privatise all of its electricity assets (utilising complex, long-term lease arrangements rather than outright sale).

Although other state governments attempted to follow the Victorian example – most notably in NSW and Tasmania – any further privatisation has thus far been prevented by trade union and community opposition. In 2000, state governments in Australia still owned (or fully controlled) over 80% of generation capacity, 74% of transmission capacity and 77% of distribution/supply sales.

It appears unlikely that further privatisations like the Victorian and South Australian programmes will be undertaken in Australia for at least several years – leaving the electricity industry in most states predominantly in government ownership, but operating through government-owned corporatised entities under “competitive neutrality” principles.

Western Australia remains the only state-owned vertically integrated utility in Australia, but a new government has been elected with a policy of dismantling the vertical integration and introducing competition, but stopping short of privatisation.

Regulation

Each of the states created an independent regulatory authority to regulate the operation of the electricity industry (as well as gas and other industries in some states). These state-based regulators remain responsible for regulating the distribution and supply functions of the industry, but regulation of the transmission systems (and high pressure gas pipelines) is gradually being taken over by the ACCC as national regulator.

Network pricing systems were designed for the dual purpose of, on the one hand, preventing monopoly profits and, on the other hand rewarding operators for their efficiency. The pricing systems are based on an “annual average revenue requirement” approach. This utilises an asset valuation formula which provides for recovery of the cost of capital and depreciation and of operation and maintenance. There is considerable controversy over the extent to which the regulators should reward operators for efficiency improvements.

The entire cost of transmission and distribution is borne by customers (generators pay no transmission charges). A “cost reflective network pricing algorithm” is used to allocate transmission costs to different nodes in the network. Network pricing remains under review by NECA and ACCC and will change in future years.

National Electricity Market Rules

The National Electricity Law, which is a series of identical laws passed in each of the participating states, gives NEMMCO the sole right to operate a wholesale electricity market. It requires generators to register with NEMMCO, and retailers and customers to purchase wholesale only from NEMMCO. This mandatory monopoly market position for NEMMCO follows the example of the UK model.

The NEM was based upon a trading model which was similar to, but slightly different from, the UK pool. The key elements were:

- Trading through the pool was compulsory for all significant generators (greater than 30 MW).
- Centralised despatch was compulsory.
- Simplified bidding rules applied and there was no provision for capacity payments, i.e. it was an "energy only" pool.
- Generators were expected to incorporate costs of start-up and recovery of fixed prices into the bids which they lodged with the pool.
- Bids were lodged on a day-ahead basis.
- Re-bidding was allowed right up to the operating half hour.

As the system developed, five minute despatch cycles were introduced.

To manage pool price volatility, market participants needed to negotiate off-market price hedging contracts between each other (often called "contracts for differences"). Off-market wholesale energy prices were set in the range of A\$37–44/MWh (excluding transmission costs) by the various states as part of the transitional arrangements to protect franchise customers (commonly known as "vesting contracts").

There are no payments for capacity, probably for several reasons. The market commenced in two states which already had excess capacity. The plant in NSW and the marginal plant in Victoria is government owned, and hence construction or re-commissioning of additional plant may occur without waiting for market signals. Instead, bid prices are limited to A\$5000/MWh, the deemed value of lost load. If demand is not met in a despatch period then the price is deemed to be this price.

NEMMCO provides two years' forward information on available generating capacity against peak load projections, and also seven days ahead against projected demand for every half hour. To meet power system security standards, NEMMCO contracts for certain ancillary services, including reactive power and black start capability. However, there are no reserve payments. Generators are only paid when they produce energy.

The number of eligible customers in the market at present is around 30 000. All these customers and all producers must have half-hour meters, and communications systems that can transmit data to NEMMCO for settlement on a seven-day billing cycle.

The market has been designed to ensure that the trading rules do not constrain bilateral trading between participants, particularly in financial hedges and derivatives. It is therefore important for the NEM to provide transparent regional prices to assist evaluation of alternative investment options between generation, demand side and network upgrades.

Outcomes of Electricity Market Reform

Employment. Employment in the electricity industry in Australia fell from 56 000 in 1992 to less than 30 000 by the end of 1999 (employment had peaked at 80 000 in 1985).

Performance. Average power plant availability in Australia increased from 84% in 1992 to 93% in 1999 (it had been 75% or less in the mid 1980s). This has led to consequential reduction in the need for reserve plant in the states.

Wholesale prices in NSW and Victoria. In NSW and Victoria, the introduction of competition – especially the vigorous competition amongst Victorian privatised generators – coupled with cost reductions and overcapacity have led to much lower wholesale electricity prices in these states since the formation of the markets. Pool prices fell rapidly following the start of the transitional national market in 1997 and a wide divergence occurred between pool prices and the vesting contract transitional prices.

For the four financial years beginning 1996–97, wholesale pool prices in Victoria averaged A\$24.7, A\$19.2, A\$25.3, A\$25.7 and A\$45.5/MWh respectively, with NSW following a similar trend. Vesting contract prices were initially much higher than pool prices, but this situation has now reversed with the rise in pool prices. The government-imposed vesting contracts thus provided generators with a substantial part of their revenues at predictable prices for transitional periods of two to five years.

There are differences of opinion about the price necessary to attract a new entrant plant in these states, but commonly held estimates put this in the range A\$32–40/MWh.

Wholesale prices in Queensland and South Australia. By contrast, lack of the same competitive pressures in Queensland and South Australia, and lower reserve margins, together with some concerns regarding the use of market power by some generators, have resulted in pool prices in those states remaining in the range of A\$45/MWh and A\$60/MWh respectively since the start of the NEM.

Delivered prices to customers. Average delivered electricity prices in Australia reduced in the mid 1990s, but have increased for the past three years. For example, average selling prices reduced by only 1% between the years 1996–97 and 1997–98 – the latter being the year in which Victorian/NSW wholesale prices were very low – and have since increased by 3% in 1999–2000 over the previous year.

The average delivered price is naturally much higher than average wholesale prices due to the addition of charges for transmission and distribution, plus the costs of supply, administration, government levies and special charges. For example the average price of electricity in Australia in 1999–2000 was A\$91/MWh, compared to average generator revenues of A\$30–40/MWh.

While some customers in some states have been able to secure significant price reductions, other customers have not yet gained much benefit or are seeing price increases. Customers in South Australia and Queensland have experienced price increases.

2.1.3 Current Objectives

The criteria which governed the design of the National Electricity Market in Australia were:

- **Competition:** The market should be vigorously competitive so that prices are always determined by competitive forces and there should be minimal opportunities for misuse of market power by one or more competitors.
- **Customer choice:** All electricity customers should be freely able to choose who they will deal with (including generators, traders and retailers).
- **Network access:** Access to all transmission and distribution networks should be available on a non-discriminatory basis to all persons who seek it.
- **Market entry:** A company wishing to enter the market at any level should not be treated more favourably or less favourably than if it were already participating in the market.
- **Trading across regions:** The rules for trading of electricity should not treat trading within any region more favourably or less favourably than cross-regional trading.

Obviously the pursuit of efficiency was a fundamental objective of the reforms. Efficiency was not, however, an explicit principle for market design. This was not because of its lack of importance but because efficiency was seen as the natural outcome if the competitive market was sufficiently vigorous.

The overriding objective remains the pursuit of competition, since the market is still young and at various stages of development in the different states. Problems associated with market introduction are a higher priority than in more mature markets. If higher efficiencies and lower electricity prices can be achieved through improved competition, it will benefit Australia's economic competitiveness, particularly in the mineral processing and manufacturing sectors. The specific lines of development, all associated with a pro-competitive environment, are:

1. To develop an open access policy for networks.
2. To deliver cost reductions wherever possible.
3. To develop effective regulation.
4. To encourage a focus on customer requirements.

The key features that are required for these objectives are listed below.

1. Open access:
 - Freedom of choice for electricity buyers.
 - Non-discriminatory access to transmission and distribution networks.
 - No discriminatory legislative or regulatory barriers for new entrants in generation or supply.
 - No barriers to interstate and/or intrastate trade.
 - Transparency of investment options between industry sectors such as transmission, generation and retail.
 - Construction of optimised interconnection capacity between states.
2. Cost reductions:
 - Reduced generation reserve margins, because reserve capacity can be shared across states.
 - Delayed investment in new plant, since existing plant can be more efficiently utilised.

- Lower overall production costs.
 - Costs of poor investment decisions will remain more with shareholders than with consumers.
 - More efficient use of electricity by consumers.
3. Effective regulation:
- Consistent regulation across the states and at the federal level.
 - The ability to detect abuse of market power.
 - The ability to analyse and challenge investment decisions.
 - The powers to force a change in behaviour and actions.
4. Focus on customer requirements:
- Full retail competition.
 - A sufficient choice of suppliers and generators.
 - Liquid markets for electricity and for derivatives.
 - Open legislation to support innovation and bundled services.
 - Equally competitive markets in financial investment and in associated energy products.

2.1.4 Proposed Programme of Change

The interconnection between Queensland and NSW will be completed in 2001, and that between Tasmania and Victoria by about 2003. Full retail competition will be introduced in the NEM area by 2003.

Whatever state of development a market has reached it will always have critics who call for further development. Developments will reflect the interests of those having the power to cause change, be they customers or traders. However, the rate of market development tends to be fastest where there is strong consumer representation. This is the case in Australia, where NECA has a shopping list of requests from the ACCC to conduct reviews of certain aspects of the market, including:

- transmission and distribution use of system charging;
- capacity payments;
- level of value of lost load, the ceiling for bids;
- ancillary services;
- inter-regional hedging;
- firm access;
- demand management.

Investors need to evaluate the impact of potential change, and markets that demonstrate a history of continual change with significant financial implications will be viewed with caution, if not avoided.

In recent times three of the state governments, the federal government and major business and consumer organisations have all called for change in the NEM, including the holding of an independent review into the effectiveness of the market rules. The process of change appears not to be complete yet.

2.1.5 Issues

Restructuring. The separation of the vertically integrated industries in each state into independent generation, transmission and distribution businesses has

progressed at different speeds and has reached different end structures. The process is politically complex and time consuming. Differences between structures in adjacent states may have an impact on inter-state trade and mutual benefit. With jurisdiction falling to individual states, the development and maintenance of consistent markets remains a challenge.

Regulation. Historically, regulation rested with the individual state or territory. However, consistent with national competition policy reforms, consistency of regulation requires that there is a shift towards national regulatory policy. Again, this involves political tension between state and national requirements. In a consumer-focused society, regulation turns out to be the growth industry in both the competitive and the monopolistic sectors of the electricity industry. Regulatory agencies being bureaucratic monopolies, their budgets and staffing have a tendency to grow rapidly, whereas the industry that they regulate contracts.

Network pricing. The principles being applied to pricing may vary from state to state; for example uniform tariffs for social equity reasons versus cost-reflective pricing. Differences can cause problems at state boundaries and inequalities in opportunity.

Market expansion. By 2003 it is anticipated that the southern and eastern states of Australia will all be interconnected. However, the inclusion of the Northern Territory and Western Australia is unlikely to make economic sense given the distances involved, so these will remain independent systems for the foreseeable future. Issues related to market expansion include the capacity of interconnections, the rights to operate them, and the impact on traders and customers.

Private sector investment. The main investments in the electricity market to date have been through privatisation sales. Future investment will be in generation growth. An issue affecting this will be the risk of operating in a merchant environment. Prices in NSW and Victoria have demonstrated that forecast prices may not be realised in reality. Once higher priced vesting contracts have terminated the expectation is that pool prices must rise. This may lead to a reaction by customers, which elsewhere has resulted in stronger regulation to support the customer position. Hence there is growing caution in the private sector towards investing in markets with such strong pro-consumer legislation and regulation.

2.2 China

2.2.1 Background

Since the early 1980s growth in electricity demand in China has averaged 8% per annum, which now equates to an annual addition of about 15 GWe of capacity. To meet this growth, China has contracted with independent power producers (IPPs) during this whole period.

However, installed capacity per capita is still only 0.218 kWe, with an annual per capita usage of only 937 kWh. Almost 100 million rural inhabitants still have no access to electricity. The recent increases in capacity have not satisfied demand growth, and must continue for decades to come. Electricity production limitations have been a significant constraint on the growth of the economy. The government's goal of doubling national economic growth between 2000 and 2010 will require a similar increase in the power industry. In 2000 the total installed capacity will reach 290 GWe, and the requirement for 2010 is expected to be 500 GWe.

China has 29 provinces served by six regional grid systems, which means that there are four or five provinces in each regional market area. Every province is overseen by both local and central government, which makes decision-making a complex process. The structure of the electricity industry comprises vertically integrated state companies, with an increasing number of IPPs selling to the single local buyer. The State Power Corporation now purchases around 65% of its power from independently financed stations. Some regional utilities also purchase from IPPs (the Shandong Power Company purchasing as much as 94% of its requirements), resulting in the average nationally having reached 50%.

Historical Drivers for Change

With production volumes in each grid area now relatively large, the challenges are:

- To continue to attract private investment at a sufficient level.
- To manage the operational problems associated with large despatching systems.
- To deliver the supply reliability required by consumers.

China's capacity target for 2000 was set at 290 GWe, requiring about 20 GWe per year to be added in the late 1990s. Of the US\$100 billion of investment required, foreign investors were expected to provide 20%. So far most inward investment (about 80%) has come from Hong Kong and Taiwan.

To date inward investment has been hindered by:

- cumbersome project approval processes;
- concerns about possible limitations on rates of return;
- concerns about limitations on foreign exchange conversion;
- opaque pricing policies;
- inadequate investment structures;
- a legal and regulatory framework which is still developing.

The key operational requirement is to load manage generation during the daily demand variation. Over 50% of generation is purchased by the National Power

Company and regional power companies from IPPs on long-term contracts which were designed to accommodate baseload operation, to fill the capacity shortfall in recent years. The contracts were based on high baseload output with short loan repayment periods and high rates of return. However, in certain regions the absence of smaller stations has required new IPPs to load modulate and reduce output. This changes the economics of these projects and places conflicting incentives on generators and the despatcher (the regional utility with whom the contract is signed).

Government Policy and Objectives

Clearly policies need to develop to address the above issues. The Electric Power Law of 1996 allows for tariffs to be set to take account of costs, "reasonable" profits and taxes. However, if contract prices are set too high then the outcome could be minimum despatch of the plant, or no despatch at all as existing contracts are not flexible enough to allow the plants to be despatched at lower levels of output. Contracts therefore need to be developed to provide for more flexible operation.

In 1997 these problems were recognised by the State Development Planning Commission, as was captured in the following position statements:

- Central organisation and management by government prevents local decision-making.
- There are almost no incentives centrally or regionally for efficiency.
- There is no transparent legal and regulatory environment for operation or investment.

The government decided that reform was necessary, shifting from the "command and control" style of management to one of encouraging commercial enterprise on a regional level. It has since initiated reforms to move the power industry towards a market economy. This includes corporatisation of power companies, with managers given more responsibility to take local decisions and the introduction of competition in generation. This will separate political and administrative activities in the electricity industry.

The existing separation of the ownership of the IPP generation assets from the ownership of transmission and distribution, together with the above developments in the generation sector, has encouraged government strategists to consider the separation of the generation and transmission markets.

2.2.2 Liberalisation Progress

China was one of the first countries to open its generation sector to private investment. The first IPP commenced operating at Longkou in Shandong in 1984. Since then numerous private generation projects selling power to the state have been commissioned. With its significant provincial differences, rationalisation of generation procurement was bound to benefit China.

In 1994 the Ministry of Electric Power decided to explore possible legal and regulatory environments for the power sector. In 1995 a programme was sponsored to develop selected infrastructure on a build-operate-transfer (BOT) basis under competitive tender. A "BOT Circular" outlined the basis of selection of projects put out for competitive tender.

The Electric Power Law came into force in 1996, to provide a framework for reform of the power sector along socialist market economy lines. This governs:

- construction of electrical power infrastructure;
- generation, transmission, supply and use of electricity;
- the setting of tariffs.

Also in 1996 the Power Purchase Contract Provisions for regulating the administration of such contracts were introduced. By this time construction growth was being limited by the availability of domestic capital, while foreign ownership of assets remained restricted.

In 1997 the government permitted foreign investors to acquire interests in power plants directly, providing that the revenues were reinvested by the owners in further power projects. The foreign joint owners were also encouraged to invest in the follow-on projects. Wholly foreign-owned power generation enterprises were, however, not normally permitted except under the BOT guidelines. Other restrictions on the foreign parties included:

- Not being allowed to own majority shares in nuclear or hydro plant over 250 MWe.
- The term of a joint venture thermal plant being restricted to 20 years.
- The foreign investor not being permitted to withdraw, transfer or assign its capital contribution without government approval.

Rising power prices and inflexibility in managing load variations caused China to consider the benefits of simulating local markets. From 1997 individual companies were encouraged to consider how to use this to reduce costs and improve efficiency. Also in 1997 the State Power Corporation of China was established as a distinct corporate entity under the Power Ministry.

In 1998 the basis for reform of the electricity industry was outlined. The Ministry of Power Industry was abolished and each province became responsible for its own industry, having a requirement placed upon it to separate generation from transmission.

Between 1998 and the end of 1999, pilot reform programmes were commenced in Zhejiang, Shandong and Shanghai to develop competitive generation markets selling to the single buyer. The trials were designed to investigate competitive generation prices and the impact on despatch, but actual accounting will not use the market prices. Systems will be developed to investigate real time pricing and accounting from 2000 onwards.

2.2.3 Current Objectives

The current short-term objectives are:

- To improve the investment environment for private investment.
- To investigate and develop suitable models for generation markets.
- To reduce the risks to the utilities in contracting for current and future power.

The key long-term objective is to commission sufficient generation in time to avoid constraining economic growth. Other objectives include:

- The rationalisation of economic despatch across the different grid systems.
- The optimisation of indigenous resources.
- The introduction of competition for despatch of generation.

2.2.4 Proposed Programme of Change

With over 50% of power now purchased from independent generation in private ownership, there are no plans for privatisation of state-owned assets. However, separation of generation from transmission and some model generation markets are being piloted to study power prices and to encourage efficiency. The following description covers proposals being tested and modelled in specific test regions.

Market Design Features

The market structure under consideration is that of a single buyer, whereby:

- There is a single buyer of power in a specific area.
- Independent and affiliated generators compete to sell.
- The single buyer usually owns the transmission system and controls despatch.
- The single buyer is the only wholesale seller to affiliated distributors and independent suppliers (e.g. municipal or county suppliers).

This model is already evolving in China and enables competitive bidding in generation. It can be developed for power pool and supply competition later.

One consideration is to provide consistent regulation across different transmission areas, and also to improve the interconnections between the areas and how the markets interact at the borders.

Each of the six regional grid operators could act as a holding company for state-owned assets, operate the high voltage transmission network and operate the regional market among the provincial members. Until full separation of generation and transmission is achieved, there would need to be some mechanism (either regulation or contracts similar to those with IPPs) to reduce favouritism towards their own affiliated generation. National and provincial regulation would be needed. To prevent a return to central control, the regulators would have to implement policy rather than make it.

The State Power Corporation will be transformed into an enterprise culture, while remaining state-run. Political and administrative functions will be separated and the provincial power companies will be established as individual entities. Pilot activities for separating generation from transmission and creating competitive power markets will be completed.

In the period 2001–10, the intra-regional power grids will be connected into a unified grid under unified despatch. Generation will be separated from transmission, so that all power plant of whatever ownership will compete for despatch under fair market rules.

After 2010 the functions of generation, transmission, distribution and supply will be unbundled. Competition will be developed in a larger area, based on a stable, competitive and disciplined electricity market.

2.2.5 Issues

Market models for generation despatch are required within each regional transmission system, together with a compatible model for despatching transfers of power across interconnections between these regions. The costs used for merit order despatch need to be reviewed, with consideration of short-run costs instead of total costs.

Enormous private investment, with a significant foreign contribution, will be required in future. To date, there remain concerns over:

- Possible limitations on rates of return.
- Opaque pricing policies, resulting in uncertainty about future tariffs under the annual review process, and hence about project viability.
- Unpredictable legal and regulatory frameworks.
- Enforcement of contractual rights, which can be difficult, lengthy and subject to political influence, leading to unpredictability.

Furthermore, IPPs with power purchase contracts containing tariffs that are high compared to competitors may find their plant despatched to the minimum levels under the contract.

2.3 Hong Kong, China

2.3.1 Background

Economic growth in Hong Kong over recent decades has been high, though the 1990s saw lower levels than the 1970s and 1980s. Over recent years growth in electricity consumption has averaged 4–5%, with total demand now being 39 TWh.

For the last 100 years, Hong Kong has been served by two vertically integrated privately owned power companies: China Light & Power (CLP), whose network mainly serves Kowloon and the New Territories; and the Hong Kong Electric Company (HEC), whose network mainly serves Hong Kong Island.

These two regional utilities are regulated by government under 15-year Scheme of Control Agreements (SCAs), with provision for interim review every five years. Under this form of regulation each of the utilities has a requirement to deliver secure and reliable supplies, with future growth adequately covered and reserve capacity constructed in time.

There are no transmission constraint problems. A limited-capacity interconnection between the utilities exists for emergencies, and there is a significant interconnection capacity between CLP and neighbouring Guangdong Province of China. CLP also sells to Shekou, an industrial district in Southern China adjacent to Hong Kong.

The utilities have constructed a range of plant types so that Hong Kong has access to a good diversity of coal, oil, gas, nuclear and some pumped storage generating plant (with the latter two being located in China). Continued investment in capacity by each utility independently, and a major slowdown in the economy since the Asian financial crisis, have currently resulted in spare capacities in excess of 30%.

The industry is robust technically and can accommodate the expected demand growth over the next three to five years.

Historical Drivers for Change

The length of the current agreements demonstrates that in the past all parties have been comfortable with the arrangements. Changes have been by mutual agreement under the SCAs.

Government Policy and Objectives

The objectives of the government have been to ensure reliability of supply, while monitoring the financial affairs of the utilities and regulating the returns on investment to acceptable levels. Government approval of tariff levels was the key control mechanism.

2.3.2 Liberalisation Progress

CLP and HEC are regulated by the government through the 15-year SCAs. The current agreements run from 1993 until 2008, with reviews in 1998 and 2003. Changes under the reviews have to be agreed by both parties. Under the SCAs the obligations of these two investor-owned utilities are:

- To provide adequate and reliable supplies at the lowest reasonable cost.
- To permit the government to monitor their financial affairs and operational performance.

In return the companies are allowed to charge tariffs which recover their operating costs plus a reasonable rate of return. The permitted rates of return are set at 15% for equity capital and 13.5% for debt capital. Shareholders have to bear interest costs up to 8%. Differences between profit after tax and the permitted return are transferred to and from a development fund used to assist in financing the acquisition of fixed assets.

Tariffs are reviewed annually for the forthcoming year and an audit review scrutinises the previous year's out-turn. Historically, tariff increases have been kept below the level of inflation. Tariffs for different categories of customers are designed to reflect the costs of supply.

The 1998 review of the SCAs introduced some control on the construction of new generation capacity, whereby a portion of the investment in capacity considered to be surplus would be removed from the asset base when determining the permitted return. Other changes to improve the monitoring process and explicitly recognise the power companies' environmental obligations were also added.

2.3.3 Current Objectives

With agreements running until 2008 and a relatively reliable power supply, CLP and HEC intend to provide high quality services under the present system until that date. The government has been active in finding ways within the agreements to alleviate upward pressure on prices. However, both sides are beginning to prepare for what may happen post 2008.

The Hong Kong power system can be characterised as follows. HEC is connected via a relatively weak transmission link to CLP that serves mainly to support mutual security. CLP in turn is connected by a much stronger transmission link to the nearest province of China, Guandong, which has a generating capacity about four times larger than that of Hong Kong. Post 2008, or before if suitable and mutually acceptable arrangements are established, the networks of the two Hong Kong utilities could be more robustly connected. Resulting inter-company transfers could result in lower cost production in the region as a whole.

The objectives of CLP and HEC will likely reflect the need to ensure their supply obligations under the SCAs are securely met, and their desire to optimise returns on investment over the next eight years and beyond, assuming various scenarios for market conditions beyond 2008.

The government's needs are likely to be to maintain the level of reliability and security of supply to which Hong Kong has become accustomed, while trying to introduce some form of competitive elements post 2008 which will demonstrate that steps are being taken to ensure electricity is delivered at the lowest reasonable cost.

2.3.4 Proposed Programme of Change

Currently there are no publicly announced, specific proposals for post 2008.

2.3.5 Issues

In comparing Hong Kong with various Asia-Pacific economies in terms of electricity tariff prices and rates of return on regulated businesses, it can be noted that the electricity industry in Hong Kong, supported by reasonable rates of return, has managed to meet rapidly growing demand requirements throughout the past three decades, albeit there is currently overcapacity. It has thus contributed directly to the economic success of the region in the period.

In contrast, some Asia-Pacific economies have not permitted price rises and have kept rates of return at low levels. This has sometimes resulted in insufficient capacity to meet existing and future demand, hence depressing potential GDP growth. These economies may also be faced with prices that must increase to attract investment and allow debt recovery in unsubsidised and liberalised markets. In these circumstances, the expectation that customers tend to have that prices will fall when liberalisation and market competition are introduced may be undeliverable in the short term.

In Hong Kong, experience of overseas liberalised markets has created the expectation that prices and rates of return could be lower, while still meeting acceptable security of supply standards and providing for future growth. The Hong Kong government is reviewing the future of the regulatory framework beyond 2008 by commissioning a study to establish whether additional interconnection within Hong Kong and the introduction of competition would benefit consumers. Political parties and some analysts are advocating the pooling of generation assets to minimise costs until new capacity is needed, and that preparation for competition should commence before the SCAs expire in 2008.

One of the current issues for the two utilities, if competition is to be introduced, is what investment strategy to employ when the outcome of future stranded cost assessments is unknown.

2.4 Indonesia

2.4.1 Background

Indonesia is composed of 17 000 islands, of which some 3000 are inhabited, resulting in the state-owned electricity utility, Perusahaan Listrik Negara (PLN), operating over 600 separate unconnected transmission and distribution systems.

The largest system, Java-Bali, is served by two generating subsidiaries and four distribution units. Around 60% of the total population of around 200 million live on Java. Many rural and island communities, such as rural cooperatives, meet their own requirements and are not connected to a PLN network. However, the national electricity plan calls for 100% of villages to be connected by 2003–04.

Indonesia had experienced growth rates in electricity consumption in excess of 13% in the years leading up to 1997. In 1994–95, when growth rates were over 15%, PLN committed itself to significant future payments to purchase power from independent power producers (IPPs). Reflecting these growth expectations, PLN was planning to meet the high growth and maintain spare capacity in some grids of 50% (double that of a well-connected and efficient system). Independent generation sales to PLN in 1994 were 0.5%, but were expected to rise to over 40% by 2003.

PLN currently has around US\$5 billion of debt, which since the 1997 exchange rate collapse is now around three times larger in Indonesian rupiah. On top of this, PLN is committed to pay several billion US dollars per annum to IPPs, some of which have “take or pay” contracts for 30 years.

In 1998 there was no significant demand growth, which exacerbated the situation regarding excess capacity. PLN’s average tariff is around Rp220/kWh, whereas its production costs are around Rp340/kWh (since almost 60% of costs are in US dollars). Consequently PLN reported losses of over US\$1 billion for 1998.

Because of a history of large numbers of supply outages, around 50% of industrial demand is self-generated. This further exacerbates the current over-commitment in capacity terms to IPPs, with power purchase agreements signed at high rates (in US dollars), which have become more expensive since the exchange rate collapse.

Historical Drivers for Change

Most of the private sector investment to date has been on Java and Bali for generation projects contracted with PLN, with very little private investment in transmission and distribution.

The current situation, with construction of too much capacity together with the associated financial commitments, must be managed. Projects may be postponed or cancelled (with associated penalties). Thus, the present focus is on financial management for the next five years.

Government Policy and Objectives

The government delivers its policies mainly through the Ministry of Mines and Energy, and in particular for electricity through the Directorate General for Electricity and Energy Development. The government’s objectives in the energy sector currently include:

- To meet the country's energy needs at lowest cost.
- To maximise the country's earnings from exports.
- To promote regionally balanced development in the country, including in the provision of electricity.

2.4.2 Liberalisation Progress

Article 33 of the Indonesian constitution includes the following principles:

- Branches of production important to the state and which dominate the life of the people shall be controlled by the state.
- Land and water and natural resources shall be controlled by the state and used for the maximum prosperity of the people.

Law 15, passed in 1985, is the foundation for primary legislation in electricity. Its provisions include:

- Article 2 states that optimising the use of resources, equality and respect for the environment are to be among the guiding principles for the development of electricity supply.
- Article 3 includes increasing fairly the welfare and prosperity of the people and stimulating an increase in economic activities.
- Article 4 declares that Indonesia's energy resources shall be utilised as far as possible.
- Article 5 makes it the responsibility of the government to perform general planning.
- Article 7 foresees government performing its duties in electricity supply through PLN.
- Article 16 states that sales tariffs will be regulated by the government.
- Article 20 regulates electricity suppliers through licensing, with penalties under Article 22.

In 1989, the government issued Regulation No. 10, which clarified the relationship between the annual electricity plan and PLN's business plan:

- Article 12 requires the holder of a public interest licence to be an Indonesian corporation.
- Article 13 requires holders of own-use licences to sell surplus electricity to PLN.
- Article 32 confirms the President's rights over sale prices, and introduces recommendations on this from the Minister of Mines and Energy to include the interest of the people, their ability to pay, and production costs.

Presidential Decree 37 of 1992 reflected the government's thinking on the availability of public financing for the electricity sector. It opened the way for private investment in power plant, expressing a preference for build-own-operate schemes. It also states that power prices are to be in rupiah and must be approved by the minister. Section 5 prohibits government guarantees for invested capital or borrowings, but it has become the practice to provide a letter ensuring that PLN will discharge its payment obligations under the power purchase agreement. These agreements require the fuel supply risk to be taken by the generator, except in limited circumstances. The decree limits the licence for a foreign investment to 30 years. In 1993 tax exemptions were provided for the importation of capital goods for projects.

In 1994 the government predicted that Indonesia's oil fields would decline in output by 5% per annum, while requirements were growing at over 7%. A new energy policy was introduced to conserve oil reserves for the transport sector and to increase the use of the sufficient reserves of coal and gas for electricity production, while also increasing hydro and geothermal output.

Also in 1994, the government passed the Investment Deregulation Law to allow private investment into infrastructure projects and to allow foreign ownership of Indonesian companies, although there remains a limit of 95% foreign ownership in the generation, transmission and distribution of electricity. The government also converted PLN from an agency with a social purpose to a limited liability company with a profit motive. This enabled PLN to create subsidiaries, enter into joint ventures and raise private sector capital.

An amendment to the regulations of the Minister of Mines and Energy in 1995 transferred responsibility for power purchase negotiations with IPPs to PLN. PLN created two subsidiary generating companies on Java-Bali, with the objective of future partial privatisation once they have demonstrated at least two years of sound finances. These will then be allowed to compete with IPPs to generate power.

Struck by the regional financial contagion in mid 1997, Indonesia experienced a economic and monetary crisis which led the government to respond by promulgating Presidential Decrees No. 39/1997 and No. 5/1998 regarding the status of some 27 IPP projects. These decrees categorised the status of all the IPP projects into the three groups: "continue", "review" and "postpone". Though these decrees were not aimed at the termination of the signed contracts, there were legal implications. These legalities were pursued through the appeal by the government and PLN to international arbitration regarding three geothermal power plant projects.

In August 1998 the Indonesian government launched the Power Sector Restructuring Policy. This proposed substantial changes in the business environment and considerable institutional restructuring. The restructuring plan aims to create a power sector that is able to grow, provide high quality and efficient electricity supply for the benefit of the consumers, and be financially independent.

This will be achieved by unbundling PLN and establishing a competitive electricity market in Java and Bali, gradually increasing the retail electricity tariff to allow full cost recovery, enlarging private sector participation in a competitive environment, clarifying the government's policy making role, and strengthening regulation. As part of the restructuring programme, Indonesia plans to implement a market structure that encourages competition in electricity production and supply, the multi-buyer multi-seller (MB/MS) market. According to the policy schedule, the MB/MS market will be implemented in 2003.

In September 1998, in an effort to resolve the problems faced by the power sector, the government established, through Presidential Decree No. 139/1998, a PLN Restructuring and Rehabilitation Team consisting of seven ministers related to the power industry. The main tasks of this team were:

- To define and review PLN operations strategic policy.
- To take measures regarding the legal relationships between PLN and third parties.

- To define steps to be taken for ensuring PLN's viability in both organisational and financial aspects.

The team started the PPA re-negotiation process in May 1999. So far, several IPPs have progressed with the signing of Interim Agreements.

In 1999 the change of government and related changes in cabinet responsibilities caused the team to be reorganised through Presidential Decree No. 166/1999. However, the responsibilities remained the same.

During 2000 the government managed to raise the electricity tariff level by about 29%. It is preparing a plan to make gradual tariff adjustments to achieve economic levels, while considering the effects this will have on the affordability of electricity for the people. The government has also considered some measures to provide for the capacity additions required in some parts of the country.

2.4.3 Current Objectives

The government's objectives in the electricity sector are set out in the five-year economic plan of 1999. Most of these tend to be guidance and hence are longer term, apart from the policy on costs. In order to reduce current costs, in 1999 PLN is reported to have informed 24 consortiums investing in Indonesia that it does not need and cannot afford their electricity.

The longer term objectives are:

- To encourage private investment to finance future growth and adequate transmission infrastructure, and to increase the efficiency of production.
- To reduce reliance on oil, by developing domestic hydro and geothermal energy, and diversifying more into coal and gas.
- To improve customer service, by decentralisation on a regional basis and corporatisation of generation, transmission and distribution in Java-Bali, and as integrated activities elsewhere.
- To conserve and use energy more efficiently.

2.4.4 Proposed Programme of Change

The government is presently considering the following developments:

- The promotion of third-party access to PLN's transmission system using a power-wheeling tariff.
- Allowing private companies to enter the transmission and distribution sectors.
- Enabling PLN subsidiaries to compete with IPPs for future growth.
- Preparing for possible privatisation of some PLN generation.

2.4.5 Issues

Land ownership. Though new generation capacity is not required immediately, the determination of land ownership and subsequent purchase has been problematic and expensive.

Tariffs. Prices do not reflect the underlying costs for different consumer sectors. There is a cross-subsidy from Java-Bali to the outer islands, and from large customers to small. Although much new rural electrification has been achieved over the last 10 years or so, much more supply connection remains to be done, and the issue is how it is funded (e.g. a subsidy given to PLN subsidiaries for social responsibilities).

Political risk. The recent change of approach of the government to private investment projects will make future investors cautious of government intentions.

Foreign debt. Indonesia's increasing foreign debt and the policies that the government uses to tackle them will have an important impact (IPPs in recent years have sought rates of return after tax of around 18% to reflect these risks).

Security of supply. Unreliability in transmission and distribution is resulting in continued privately owned self-generation.

Regulation. There is a need to develop a suitable regulatory organisation for the large number of existing and future IPPs.

2.5 New Zealand

2.5.1 Background

The central government has been involved in the planning and standardisation of New Zealand's national electricity system since before 1900. Generation and transmission were the responsibility of the Electricity Division of the Ministry of Energy, which was also responsible for policy advice and regulatory functions. There was extensive political influence in generation investment, which took account of employment and other socio-economic factors. Project management did not meet current standards, and political factors were involved in determining wholesale pricing.

Before 1999, 96% of the capacity of 8.2 GWe was government-owned. The remainder was small hydro providing peak lopping capability for local supply companies. Hydro provides about 75% of generation, but it is essentially run-of-river, averaging only 6–8 weeks storage capacity. Fortunately, the North Island hydro reservoirs are fed by winter rains, at the time of highest demand. Spring snow melt replenishes the South Island reservoirs to support supply. In the North Island there are eight natural gas stations and two baseload geothermal stations.

A major feature of the transmission system is the DC link between the North and South Islands that is capable of transporting 1200 MWe northwards, less towards the south. This creates a major constraint that requires one of the largest generating units on the North Island to hold spinning reserve to cover potential loss of supply.

Local distribution and supply were the responsibility of electricity supply authorities (ESAs), apart from a few large customers supplied directly by the government. In 1985 there were 61 ESAs, though numbers had been much higher previously. These were electorally oriented, statutory monopolies, which were non-profit making and carried no debt. Inefficiency, lack of customer choice and cross-subsidies resulted. Tariffs for domestic customers were generally subsidised from commercial and industrial tariffs, and some were below cost. A small number of large customers was permitted to purchase at the same annual bulk rates as the ESAs.

In the early 1980s, a major inter-departmental review of the government's role in the electricity industry was commenced, looking to separate operational from other functions, and to improve commercial performance and introduce commercial disciplines for trading activities.

Historical Drivers for Change

There was considerable concern about New Zealand's economic performance in the early 1980s since government debt had risen to high and unsustainable levels. The new Labour government decided on a radical overhaul of the economy which led to stronger public sector accountability. Outcomes sought included economic growth through efficient resource use, driven by clearer price signals and, where possible, by competitive markets. This process led to the deregulation of banking, ports, airports, air traffic control, railways, telecommunications and some postal services, as well as the gas and electricity industries. Some major state assets were sold to start repayment of overseas debt.

Electricity planning had become more difficult than in the previous 40 years, during which annual demand growth of around 10% was experienced. There was now a perception that power planning was too far ahead of demand and was too costly. The most recent hydro station had run so much over budget that this perception was widely accepted, and it became clear that the government could no longer afford and was no longer willing to continue to invest in new generation.

Government Policy and Objectives

The New Zealand government's energy policy objective is: "To ensure the continuing availability of energy services, at the lowest cost to the economy as a whole, consistent with sustainable development. This will be achieved by the efficient and effective provision of energy services through properly functioning commercial systems with competitive incentives. These systems will work within an effective and stable regulatory environment and take energy conservation into account."

The key objectives are:

- To promote competition.
- To remove statutory barriers and controls.
- To counter anti-competitive behaviour, and the potential for it, through general competition law.
- To provide commercial incentives.
- To corporatise, and privatise where appropriate, government trading activities.
- To promote energy efficiency and renewables.

2.5.2 Liberalisation Progress

The first major step towards reform of the industry came in 1986 with the passage of the State-Owned Enterprises Act, which became an important vehicle in the transition from the historical hierarchical government structure to the current segmented and competitive market structure. The government announced its decision to reform its trading activities, including the generation and transmission sectors of the electricity industry. In addition, an inter-departmental committee was set up to develop and coordinate distribution reforms.

In 1987 the Electricity Corporation of New Zealand (ECNZ) was established as a company under the State-Owned Enterprises Act, to own and operate the generation and transmission assets of the Electricity Division of the Ministry of Energy. The Division's policy and regulatory activities were separated out, and largely retained in the Ministry of Energy.

Under the Act, state-owned enterprises are companies in which nominated ministers hold all the shares, but they operate with commercial structures and incentives and with the principal objective of being successful businesses. ECNZ owned 95% of the country's generation assets and all the transmission grid assets. It sold wholesale electricity to around 52 locally owned distributors and seven major energy users.

The Electricity Amendment Act 1987 came into force on 1 January 1988, removing the need for the Minister of Energy to approve all new hydro generation proposals. ECNZ restructured its activities, setting up Transpower as a subsidiary to run the transmission network, leaving ECNZ solely as a generator.

In 1989 the Electricity Task Force, set up in 1987, recommended:

- Separate ownership of generation and transmission.
- No large scale break-up of generation.
- Further study of limited generation break-up and creation of a wholesale market (subject to this, ECNZ to be privatised).
- Transmission to be owned by a “club” of generators and distributors.
- ESAs to be corporatised and privatised.
- Removal of statutory franchise areas and obligation to supply.
- The development of a light-handed regulatory regime, drawing on the Commerce Act 1986 supported by public information disclosure.

The Ministry of Energy was abolished with effect from December 1989. Its policy, regulatory and other non-commercial roles were transferred to the Ministry of Commerce. In 1990 the government announced that ESAs would be corporatised. Electricity boards were to be owned by local trusts. Municipal electricity departments were to remain in local authority ownership. In July 1990 an Establishment Board was set up to restructure Transpower as a separate corporate entity from ECNZ, with a plan for an ownership club or another form of ownership.

In its 1991 report to the government, the Establishment Board recommended ownership of Transpower by a club of ESAs and generators. At the same time, it recommended a process for separation of Transpower from ECNZ, including valuation, gearing and pricing. The Energy Sector Reform Bill was introduced to parliament. It was later split to become five separate Acts, including the Energy Companies Act 1992 and the Electricity Act 1992.

In 1992 the government confirmed its energy policy framework, reproduced above. In July of that year the Energy Companies Act came into effect, providing for the corporatisation of the ESAs. Local distributors were required to adopt company structures, the ownership of which was vested in various forms:

- Local trust ownership was most favoured.
- Majority private shareholding resulted in some cases.
- Municipal electricity departments and a small number of boards were owned by local government.
- Many combinations of the above.

Generation reform and the creation of wholesale market arrangements had been given less attention than distribution and retailing. In October 1992, the Wholesale Electricity Market Study (WEMS) was released. This was a private sector initiative which recommended a major evolution of existing market arrangements to provide a predictable price path for wholesale electricity, and to enable some trading at marginal prices. Competition with the dominant generator ECNZ was envisaged. The government responded by calling for an independent review of the WEMS report. Also in October 1992 the government set up the Energy Efficiency and Conservation Authority to develop, implement and promote strategies to improve energy efficiency.

The WEMS critique was presented to the government in 1993. It identified five areas for further consideration and development:

- The pricing of tradable contracts.
- Ground rules for market operation, with the threat of heavier regulatory oversight.

- Oversight of the performance of the wholesale market in improving energy efficiency.
- The need for a wider review of the wholesale electricity market proposals, including by parties not involved in WEMS.
- The possibility of evolutionary development if one-step introduction of new arrangements turned out to be impracticable.

In April 1993 the Electricity Act 1992 came into effect. This provided for:

- The removal of distributors' statutory monopolies and of the obligation to supply.
- Information disclosure, focused particularly on natural monopolies.
- Provision for temporary price controls for domestic consumers.
- Safety matters.
- Land access.
- The role and wind up of the Rural Electrical Reticulation Council.
- Compulsory maintenance of distribution services until 2013 (20 years).

Also in April 1993, the first franchise restrictions were removed. These only covered small retail customers under 0.5 GWh per annum, to avoid the possibility that they might face the costs of cross-subsidy, since competition for larger consumers was expected to be stronger.

In May 1993 the government announced the decision to separate Transpower from ECNZ. "Club" ownership was seen as difficult to implement, so the government decided to set Transpower up as a stand-alone state-owned company. Special legislation would be required. In June of that year the government announced it would establish the Wholesale Electricity Market Development Group (WEMDG) to develop specific, cost-effective proposals for developing a wholesale electricity market that, consistent with sustainable development, would ensure that wholesale electricity was delivered at the lowest cost to the economy.

The Electricity Market Company (EMCO) was set up by the Electricity Supply Association and ECNZ (later joined by Transpower), to develop an electricity market framework for wholesale trading. Key steps included:

- Commencement of an on-line secondary market in trading of ECNZ's hedge contracts, including provision of market information.
- Establishment of a market surveillance committee to admit new entrants and supervise conduct.
- Administration of the Metering and Reconciliation Information Agreement (MARIA), to record and reconcile flows of data to meet the needs of parties contracting in the wholesale and retail markets. Under MARIA, Transpower, as National Reconciliation Manager, reconciles information against contracts and passes information for billing back to market participants.

In April 1994, a second franchise removal extended competition for supply to all consumers. Also in April, the government amended its announcement of May 1993 setting up Transpower as a stand-alone state-owned enterprise. The separation of Transpower from ECNZ took place on 1 July 1994. Also in July, the Electricity (Information Disclosure) Regulations came into force, releasing much information, including monopoly financial statements, prices of contracts, performance against assets, and costs and revenues by tariff category.

In August 1994 the final WEMDG report recommended:

- Early establishment of a competitive wholesale market.
- Sale of most electricity under long-term, tradable contracts.
- Establishment of a voluntary pool and spot market operated by a neutral entity.
- An independent Transpower.
- Steps to stem ECNZ dominance, including progressively leasing approximately 40% of its plant and constraints on its new investment.
- A levy to promote energy efficiency and conservation.

In 1995 the government made provisional announcements on the steps it would be taking in the lead up to the opening of the wholesale electricity market:

- ECNZ would be split into two competing state-owned enterprises (ECNZ and Contact Energy).
- ECNZ's Maui gas contract would be transferred to Contact Energy.
- ECNZ's proposed new plant at Taranaki would be sold (including associated gas supply).
- Six small hydro plants owned by ECNZ would be sold.
- The remaining assets of ECNZ and Contact Energy would not be sold.
- Special constraints on ECNZ would be introduced, to apply until its market share fell to 45%.
- A five-year fund of NZ\$18 million would support energy efficiency in the domestic sector.

Later in 1995, Contact Energy was formed as a second government-owned generator by transferring 27% of ECNZ generation. It commenced commercial operations in February 1996 in competition with ECNZ. Contact took over power stations representing 22% of total electricity production. As the government had announced, Contact also took over ECNZ's contracts for Maui gas, and special restraints applied to ECNZ until such time as its market share fell below 45%.

In April 1996, an interim wholesale market commenced with an administered pricing arrangement. In October the full market commenced operation. Buying and selling takes place at a spot price, which is not capped and is formed from open offers and bids. The market is operated by EMCO and despatched by Transpower. The spot market is supplemented by the trading of longer term hedge contracts.

Transpower's objectives were revised in 1997 to emphasise more strongly the need for it to improve continually the efficiency of transmission services, by making the services contestable wherever possible and producing customer-driven services at least cost. The key outcome sought by the government was to reduce transmission costs as a percentage of total electricity costs on a sustainable basis.

In 1998, the government announced a package of reforms due to come into effect in early 1999. The outcomes sought were vigorous competition wherever possible and effective regulation of natural monopoly businesses. Key features included:

- The decision, in principle, to split ECNZ into three state-owned enterprises.
- Ownership separation of distribution and energy businesses.
- Monopoly distribution businesses to face increased risk of price control if they failed to deliver best possible prices to consumers.
- Strengthening of the Electricity (Information Disclosure) Regulations 1994 and the handbook for valuing distribution businesses.

- Publication by the government of improved analysis of disclosed information to enable better comparisons of the performance of power companies.
- Requiring the industry to establish low cost switching arrangements to enable customers to change retailers; the government would introduce a mandatory default system if the industry failed to deliver within 12 months.

In July 1998, the Electricity Industry Reform Act required corporate separation of distribution and energy businesses to be achieved by April 1999, and full ownership separation no later than the end of 2003. In September the government announced its decision to consider selling Contact Energy, thought to have a book value of NZ\$860 million.

The government sold 40% of Contact Energy in 1999 to Edison Mission Energy for NZ\$1.208 billion. New Zealand's largest electricity generator, ECNZ, was split into three competing state-owned generators: Genesis Power, Meridian Energy, and Mighty River Power. The industry chose to move more quickly than required by law and completed ownership separation before 1 April 1999. At that date, there were seven electricity retailers. Merger activity was less pronounced among distribution businesses, of which there were 31 on 1 April 1999.

The Electricity (Information Disclosure) Regulations 1999 come into force, replacing the 1994 version. The new regulations included:

- Removal of disclosure requirements from retailers and generators (reflecting their need for commercial confidentiality to compete in the market place).
- Tightened rules for accounting and for calculating performance measures.
- New measures for reliability of performance.
- A requirement for distributors to disclose asset management plans and security of supply standards, as recommended by the ministerial inquiry into the Auckland power failure.
- Provisions for much disclosed information to be made available on the Internet.

In May 1999, the government sold its remaining 60% share of Contact Energy to over 225 000 retail investors at NZ\$3.10 per share. The government's revenue from the sale of all of Contact Energy then totalled more than NZ\$2.3 billion.

2.5.3 Current Objectives

The government's policy framework has not changed from that expressed in 1992, although some policies have developed as understanding of competition has improved. In particular, the position on the splitting of companies and privatisation developed rapidly in the late 1990s, compared with the early 1990s, when there were recommendations not to split generation.

The following broad objectives provide guide present policy:

- Minimise regulation and rely on existing industry processes where consistent with reform objectives: "As much competition as possible with as little regulation as necessary."
- Encourage competition by creating an environment where contestable elements are exposed to competition in order to improve the efficiency of production and allocation and of investment decisions, and to reduce costs.

- Constrain monopolies and regulate those elements not susceptible to competitive pressures to facilitate competition in upstream and downstream markets, in part through eliminating monopoly pricing.

The New Zealand government has passed an enormous amount of legislation to deregulate its energy, in particular its electricity, industry. Draft proposals have been followed by consultation and review, before final legislation. The policy of light-handed regulation has been defined as one in which there is no government regulator and, instead, free competition in as open an environment as possible is regulated by competition law.

The development of the market by the industry and other concerned parties was a process sanctioned by the government, which decided the structure and size of participating companies. Some components of the state-owned industry have been privatised and more may follow in future. Another aspect of market development has been the time period of 15 years considered to be reasonable to deliver the benefits of competition. The timescale for the reforms was clearly relaxed, though many other associated legislative changes were taking place. At certain stages the private sector, which was typified by the new distribution and supply companies, became impatient with government progress and took the initiative.

The aim of the government in initiating reform was to remove itself from decision-making and risks such as large-scale investment in generation, which it preferred to leave in future to the private sector. As the owner of generating assets the government had an interest in maintaining prices, but it wished to see downward movement in prices which would bring benefits to the economy as a whole.

It is significant that lower prices for the end customer have not materialised as yet, though there have been competitive movements upwards and downwards at the wholesale level. The government has accepted that lower wholesale prices resulting from competition in generation and from splitting ECNZ may reduce the overall value of state-owned assets on privatisation. The value realised for Contact Energy, however, was much higher than expected the previous year. The government has demonstrated its concern with achieving good returns by the long timescale for introducing competition and in its tolerance of no significant asset price reductions to date.

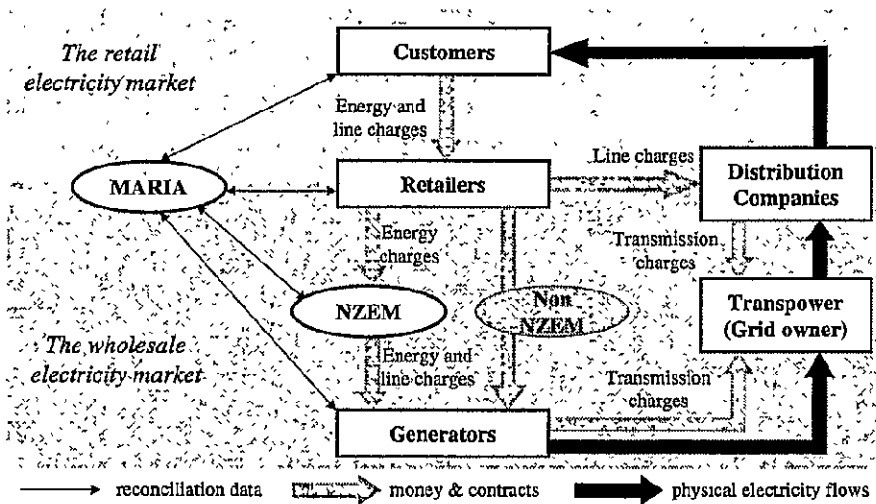
Once the remainder of ECNZ is privatised, it is predicted that the government will take a more aggressive approach to price reductions and possibly towards regulation.

Market Design Features

The New Zealand Electricity Market (NZEM) is a voluntary market, which means that generators can sell their output via on-market trades through NZEM, or via off-market trades under bilateral contracts. These two forms of trade must be reconciled and mismatches handled appropriately. This is done via MARIA, which is itself a voluntary agreement. However, bilateral contract trading (which predominates) requires a contract with Transpower for grid operation and despatch, and membership of MARIA for reconciliation.

The physical and financial flows, together with the relationships between participants, are indicated in the diagram below.

Electricity Market Relationships



Regulation

An important part of the government's energy reform policy involved the repeal of a number of historical restrictive electricity regulations. This included the removal in the 1980s of restrictions on the construction of new power stations and power lines, and on the choice of electricity suppliers (provided that the provisions of the Resource Management Act, the Commerce Act and the Fair Trading Act were complied with). This formed the basis for New Zealand's light-handed regulatory structure, in which there is no industry regulator or regulatory body. This is in contrast with many other electricity markets around the world where industry costs and workforces are contracting rapidly, yet those of the monopoly regulatory departments are growing rapidly.

Recently the New Zealand government has introduced more specific regulation intended to control the activities of distribution businesses, which are natural monopolies. The first step was the Electricity (Information Disclosure) Regulations, which require public disclosure of:

- Separate audited financial statements for the distribution and energy components of power companies.
- Prices and other main terms and conditions of contracts.
- Financial performance measures based on a standard approach to valuing assets.
- Efficiency and reliability performance measures.
- Methodologies behind various charges.

The purpose of these regulations is to discourage monopoly pricing and promote reliability of electricity systems by enabling comparisons to be made between the different distribution businesses. More recently, the Electricity Industry Reform Act was enacted. It provided for corporate separation of distribution and energy businesses to be achieved by 1 April 1999 and full ownership separation no later than 31 December 2003. Most if not all of the companies have chosen to sell

either the distribution or energy components of the business. Legislation has also been proposed which would regulate more directly pricing by distribution businesses through provisions of the Commerce Act.

Against this background of relatively minimal regulation the industry has developed a strong tradition of self-regulation. This has primarily been done by multilateral contracts. These industry multilateral agreements collectively form the basis of self-regulation of the electricity industry, and will continue to be developed over time. Examples of these contracts, which were described above in more detail, are:

- The Metering and Reconciliation Information Agreement (MARIA) that establishes technical metering and reconciliation standards for the industry, which are necessary for retail competition.
- The NZEM rules and governance processes, which established the New Zealand Electricity Market, the market for wholesale electricity.

Self-regulation extends to enforcement issues as the industry has also established surveillance functions to monitor compliance with the industry agreements.

Electricity Market Rules

NZEM is administered on behalf of its participants by the Marketplace Company (M-co), which also conducts the pricing and clearing functions. NZEM is a multilateral agreement between participants, who include generators, purchasers and traders. A trader may trade financial contracts through NZEM. The agreement covers, among other things, the rules for voluntary trading of spot electricity, selection of the governance board, changing the rules, resolving disputes, and enforcement.

Generators' offers and purchasers' bids for supply volumes at specified prices are made by 13:00 each day for each half hour of the following day. Revisions can be made up to two hours before the trading period. For the expected level of demand a schedule of power station generation is determined, together with a marginal price forecast from the supply and demand balance for each half hour.

The generation schedule is the responsibility of Transpower, which as central despatcher and system operator is responsible for the physical realities and supply security requirements of the grid. In general, bilateral traders will have a despatch contract with Transpower that enables them to self-despatch. The forecast schedule and indicative spot price are then completed using the bids and offers made to NZEM. Currently, reconciliation mismatches are balanced by trades in NZEM, so that the schedule to meet the actual electricity taken from the grid in each half hour, and the final price used for payments, are determined ex-post using the offers and bids made to NZEM.

Generators can input electricity at over 40 injection points and purchasers can take electricity from over 200 exit points. The transmission of electricity incurs losses, and transmission constraints may require more expensive generators to operate. Consequently, the costs of taking and inputting electricity at the different locations are all different. NZEM establishes different prices at all of these locations, which are called nodes.

Transpower and connected parties have an obligation through their transmission contracts to meet standards of supply security and quality of supply. Transpower contracts with generators, consumers, retailers and distribution companies for a

range of ancillary services, including short-term reserve and reactive power. At present the costs incurred by Transpower are recovered from generators and distributors through connection contracts.

The rules of MARIA record the arrangements for the measurement and metering of electricity flows in the transmission and distribution networks and their reconciliation with contract arrangements between parties. The rules establish a contestable contract between the members of MARIA and a service provider who carries out a national reconciliation of all wholesale and retail electricity flows. The national reconciliation manager is currently a subsidiary of Transpower.

2.5.4 Proposed Programme of Change

Given that the government's policy and objectives remain as initially stated, one would expect to observe the continuing development of pro-competitive measures, and that a review of progress would show some success. A common response to several areas of this study has been that it is "too early" to observe significant benefits, such as large reductions in prices and increased efficiency.

However, markets often do demonstrate early benefits following particular changes. In terms of electricity prices, notable changes have been rises since 1995 in industrial prices and even larger rises in domestic prices. Commercial prices have held firm in nominal terms and fallen in real terms. Wholesale energy prices through NZEM fell between 1997 and 1998 by typically 15–20%, and after the restructuring of ECNZ into three competing entities in April 1999 prices saw a further reduction.

Prior to 1999, when power companies had not yet separated their distribution and supply businesses, energy price reductions were not being passed through to customers, despite full retail competition. The Electricity (Information Disclosure) Regulations 1994 require certain information to be released, which enables comparisons of distributors' performance.

Information for 1997–98 showed "improved rates of return for the industry as a whole", even though typical levels are in the range 5–10%. "Further reductions in costs, combined with overall real average revenue increases, have contributed to the improving returns to shareholders." There was "a slight decline in the amount of energy delivered on behalf of others, indicating no overall change in the apparent level of retail competition". The fact that this level represents around 1% of total energy, and only around 2% of customers have changed supplier to date, indicates essentially a zero impact when compared to other markets where retail competition has been introduced.

A review of performance might therefore encourage the government to speed up change in the following areas:

- Firmer regulation of distribution and supply businesses, creating benchmarks using the data already provided to force price reductions.
- Privatisation of the three ECNZ subsidiary generators to force competition in the already over-capacity generation sector.
- Introduction of efficiency incentives for the transmission company, Transpower, in all its activities (these appear to be absent at present).
- Introduction of incentives for energy efficiency and renewables (this aspect of policy seems to have been overlooked).

2.5.5 Issues

With a competitive market framework already in position, the remaining major issue has to be the completion of the restructuring of the industry into a form that does force competition. With production dominated by hydro, prices are relatively low by international standards. A possible drive towards even lower prices has been diluted by the government in trying to realise full value in the privatisation of its own assets, instead of transferring the benefits more directly and more rapidly to consumers via price reductions, which would benefit the whole economy. This is a situation that occurs in many countries with government-owned power industries. The favoured route seems to be:

- Sell state assets at as full a value as possible, with a market framework proposed or already in place with special features designed to support the asset value.
- Once assets have been sold (though possibly not in their entirety since government retention may be beneficial later), introduce robust competition and regulation, removing the special features.
- Fix the time-frame to maximise a suitable financial function, such as national wealth, GNP, GDP or government funds, accounting for future revenues from taxes on the privatised electricity industry, and on the increased profits of large industrial consumers.

This may seem rather sanguine from an investment point of view, but it represents a profit maximising strategy for a government, which is after all a monopoly, if it has a strong majority.

Prices. Price is the single indicator that best measures the health of a product. In the case of New Zealand, it can be said that it does relatively well in international comparisons of electricity prices. Even so, with the natural advantage of low hydro generation costs, competition and consequential efficiency gains could produce beneficial price reductions. Since the state of the economy was the driver for change in the 1980s, relevant features are costs and prices. To the customer, price is the driver, and the New Zealand customer is still waiting for the benefits after over 12 years of development and over six years of market operation. It is therefore an issue.

Privatisation. The sales of the three ECNZ generators and of Transpower are possibilities for the very near future, and could realise over NZ\$7 billion.

Incentives in transmission. Efficiency incentives in transmission seem to be absent. In other markets reductions in charges of over 20% have been possible. The following questions have emerged from this study:

- What costs should be recovered via connection charges and contracts?
- Who determines and who pays for the grid operating supply security policy?
- Does Transpower compete with others to meet its own ancillary services requirements?
- What incentives are there for Transpower to reduce costs?

Incentives in distribution. The issue is, what incentives are there for distributors to reduce costs? It seems that regulation of distributors is not firm enough, as evidenced by the following:

- Charges are increasing.
- Energy delivered for others is falling.
- Only 37 000 customers, or 2.4%, have switched suppliers.

Retail competition. This very low rate of customers switching suppliers is surprising, when available savings are said to be worth up to 20% of bills. Either this saving is not worth the effort on the part of the customer, or there are impediments to switching. Firmer regulation is needed to identify and remove these impediments.

Competition in generation. With the market fragmented by various constraints into effectively over 200 locational nodes, and with production sectorised into baseload, mid-merit and peaking duties, it is physically very difficult to achieve widespread competition because of these localised effects. With the potential number of portfolio generating companies being only four, together with a small number of independents, natural competition will never be aggressive without further incentives.

Zonal pricing would cause less fragmentation, and splitting ECNZ into more companies than is presently planned would help create more competitors. A key parameter here is the size of company versus the over-capacity in production.

Investment. It remains to be seen whether investment via commercial contracts will deliver independent new generation into the open market. Existing portfolio generators, co-generation and embedded generation all have strategic advantages and incentives. With existing over-capacity it may be many years before this issue is addressed.

Cross-subsidies. Cross-subsidies always exist when costs are bundled, zoned or allocated against other revenue streams. Some are relatively transparent, including domestic to commercial price differentials, transmission constraint costs, and losses recovery charging.

2.6 Philippines

2.6.1 Background

The Philippines is an archipelago of more than 7100 islands in South East Asia. The country is divided into three major island groups. The Luzon group, including Palawan, is the largest, representing about 35% of the total land area of the country. The Mindanao group in the south is the second largest and includes the islands of Sulu and Tawi-Tawi. The Visayas is the third major island group, and includes Cebu, Bohol, Panay, Samar, Negros and Leyte.

The Philippine power system consists of three major island grids, namely Luzon, Visayas and Mindanao; there are also several small island grids. The Luzon grid is the largest, accounting for 75% of total generation and installed capacity. The Visayas grid comprises the islands of Cebu, Leyte, Negros, Panay, Samar and (soon) Bohol. Together they amount to around 10% of total generation and installed capacity. The Mindanao grid accounts for about 15% of total generation and installed capacity.

Luzon, which includes the capital Manila, has about 75% of national electricity demand. Prices are such that industrial and commercial customers subsidise residential customers, and the Luzon grid subsidises those of the Visayas and Mindanao.

Prior to 1987, electricity production was solely the responsibility of the government-owned National Power Corporation (NPC). Although the NPC remains the principal generator, a significant portion of generating capacity is now being operated by independent power producers (IPPs). Responsibility for transmission still remains with the NPC. Since 1995, the NPC has allowed "open access" over the high voltage transmission system, allowing IPPs to sell directly to distributors and large industrial customers.

In 1999, IPP installed capacity stood at almost 50% of total generating capacity, accounting for 50% of the total of around 40 TWh of electricity produced. As a consequence of the Asian economic crisis in 1997, projected load growth did not materialise. The result was that NPC plants are now under-utilised, with the spare capacity margin being about 50% of demand on average.

By about the end of 2000, grid interconnections between the main Visayas group of islands were expected to be completed. The main island of Luzon is interconnected to the Visayas grid through a double circuit 350 kV DC link which now allows transport of about 480 MWe of geothermal energy from the Visayas. Another submarine HVDC link with a capacity of 500 MWe is planned to be in place by 2004 between the Visayas and the hydro-dominated Mindanao grid. In addition, there are also small isolated island grids, predominantly located in the Visayas region, which are served by small diesel generators.

Distribution is performed by 27 private and municipality owned utilities, and also by 119 rural electricity cooperatives. The largest privately owned distribution company by far is the Manila Electric Company, which distributes more than 75% of national sales. About 76% of villages are electrified and connected to the main grids, and the government aims to extend electrification to all villages by 2004.

The Philippines has a large gas field some 500 km off-shore from Luzon. Gas-fuelled generating plants are under construction, and a gas pipeline from the Malampaya gas field in Palawan island is expected to be operational by 2002. By about 2003, good fuel diversity is expected to be achieved between hydro, coal, gas, oil and other sources (e.g. geothermal, wind, etc.). The Philippines is the world's second largest producer of geothermal power, after the USA.

Historical Drivers for Change

In the early years of the 1990s a significant contributor to the country's low economic growth of 2% per annum was the power crisis which commenced in 1989. During this period, which lasted until 1993, demand growth outstripped capacity and outages of 4–8 hours a day became commonplace. Inconsistent government policies, political intervention (particularly the non-operation of a 650 MWe nuclear plant) and heavy-handed regulation and control of the NPC were major factors contributing to the failure to deliver a more efficient and productive electricity industry.

Government funding was inadequate and revenue income was insufficient to fund the investments needed to meet the growth in demand, as well as to replace ageing plants. Power shortages were eventually resolved through government liberalisation of the sector, allowing private investment in electricity production. This allowed the NPC to concentrate on transmission and improving the backbone grid systems through interconnection.

By the end of 1994 the private sector had added some 2.5 GWe of capacity, sufficient to meet 40% of the aggregate demand in the three main transmission grids (Luzon, Mindanao and Visayas), and economic growth had risen to 8%. However, the Asian economic crisis during late 1997 and the consequent fall in electricity demand in 1998 resulted in over capacity in generation, leading to NPC plants operating at below optimum levels.

The HVDC interconnection between the Visayas and Mindanao is being pursued to allow the transmission of excess geothermal energy from the Visayas, in anticipation of demand growth in Mindanao and the rest of the grid by about 2004.

The government's forecast is for an average growth in demand of about 9% over the next 10 years. This will require about 14 GWe of plant construction and further funding of over US\$20 billion. The requirement is therefore to create a market environment that encourages private investment to provide this additional capacity. The government wants to reduce its own financial risks by requiring the private sector to assume risks in the future generation market. This would mean doing without long-term contracts with the government or other government guarantees.

Similarly, the government wishes to encourage investment in the distribution sector to connect some 10 000 villages to the main system.

Government Policy and Objectives

The matter of restructuring the power sector and privatising the NPC has been the subject of many studies, discussions and public consultations in both the executive and legislative branches of the government.

The objective of the proposed reforms is to make sure the country will have reliable and competitively priced electricity. The strategy is to put an end to monopolies that breed inefficiency, to encourage the entry of many more industry players, and to promote robust competition in generation and supply that will benefit consumers in terms of better rates and efficient services.

The privatisation or sale of NPC's generating assets to seven independent companies is expected to trigger competition in the generation sector. This will also effectively shift the burden of providing the necessary financing for capital-intensive power generation plants from the government to the private sector.

With the relatively recent power shortages in mind, together with high forecast growth and the country's present low per capita GDP and electricity consumption, the government's policy is focused on the requirement to deliver a reliable and secure supply of electrical power. To improve social conditions for the population, another, compatible, requirement is the total electrification of the country.

To deliver these requirements the government has the following enabling objectives:

- Increase the investment of private capital in the power industry, while minimising the government's financial commitment.
- Create an environment of competition and accountability.
- Deliver competitive and affordable prices.
- Improve operational and economic efficiency.
- Make transparent the social subsidies.
- Share social and other costs among all users.

Present Industry Structure

Under the present industry structure, the NPC operates its own generating plant and also buys additional electricity from IPPs. It provides supplies to distributors, which comprise privately and municipality owned utilities and rural electricity cooperatives, and also to large industrial customers.

The Energy Regulatory Board (ERB) regulates the tariff rates of the NPC, as well as those of the distributors and cooperatives. The Department of Energy (DOE) sets policy direction for the energy industry, while the National Electrification Administration (NEA) provides financial and technical assistance to electricity cooperatives.

2.6.2 Liberalisation Progress

Presidential Decree 40 (issued in 1972), gave the NPC a virtual monopoly over the generation and transmission of electricity. In 1973, the National Electrification Administration (NEA) was created, to implement the government's national policy on total electrification of the country. The NEA provides financial support for loans to the 119 rural electricity cooperatives. From 1986 petroleum product prices and electricity tariffs were set by the Energy Regulatory Board (ERB) under the Office of the President.

Executive Order 215 of 1987 amended the NPC's responsibilities to allow private entities to participate in power generation through co-generation, build-operate-transfer (BOT) and build-operate-own (BOO) schemes, though responsibility for strategic development remained with the NPC. Plants built under the NPC's power development programme must sell their output to the NPC. In 1990, the

Build-Operate-Transfer Law was approved to further encourage private sector financing of power infrastructure projects.

In 1992 the Department of Energy was re-established (after it was abolished in 1986), charged with energy planning, accreditation and connection. The Republic Act 7638 stated that the energy programme should be updated to include a policy direction towards the privatisation of government agencies related to energy, and towards deregulation of the power and energy industries.

The Emergency Power Crises Act of 1993 finally addressed the power crisis (which had resulted in daily 12-hour brown-outs) by giving the President special emergency powers to contract with the private sector for the necessary additional generation capacity. It also raised the maximum allowed rate of return of the NPC to 12%, although this has yet to be applied.

From 1995, IPPs were allowed to sell to distribution utilities directly. New regulations also established competitive procurement procedures for power projects and a methodology for calculating the avoided costs of a utility contracting with an IPP. In addition, the range of possible construction contracts was extended from the limited BOT model.

Also in 1995, Congress started to develop a bill to define the future structure of the electrical power industry and the responsibilities of the various agencies and entities. Debate and redrafting has continued, and the legislation had still not been approved in 2000.

2.6.3 Current Objectives

The introduction of IPPs into the Philippines was a success, in that it resulted in the power system being able to meet demand, which was the priority in the early 1990s. However, there are significant concerns over funding, debt repayment and efficiency which remain to be resolved by the industry. These include:

- Supply reliability remains a long-term risk due to the massive financial requirements and an over-stretched infrastructure budget.
- A significant financial responsibility and market risk continues to fall on the government.
- Retail electricity rates are among the highest in Asia.
- The pricing structure does not reflect true costs and subsidies are not transparent.
- There are inadequate incentives for efficiency due to the absence of true competition.
- There is inadequate accountability for reliability, cost, performance and quality of service.

In the short term, the objectives for the electricity sector are:

- To continue to encourage greater private sector investment and participation in power sector activities.
- To restructure the power sector to promote efficiency and accountability.
- To unbundle the NPC's transmission and generation businesses, prior to privatisation of both.
- To pursue the use of natural gas for power generation.
- To manage the emerging excess capacity.

In the longer term, the key objective is to provide reliable and efficient supplies of electricity. This has other supporting objectives:

- To diversify energy sources for power generation.
- To exploit indigenous fuel resources.
- To diversify the sources of both local and imported energy.

In terms of efficiency in pricing, the objectives are:

- To unbundle and rationalise electricity prices to encourage efficiency in generation, transmission, distribution and consumption by end users.
- To implement marginal cost based electricity tariffs.

2.6.4 Proposed Programme of Change

Private power investment to date has been successful. To continue this success and expand the benefits of competition, the government has initiated reforms, the objectives of which are:

- To create an environment which encourages sufficient investment to meet growth.
- To develop a competitive environment to encourage efficiency and reliability.
- To develop a regulatory framework to protect customers, while delivering growth by ensuring commercial viability.

These will contribute directly to meeting the government policy objectives presented earlier. The issue of subsidies is being addressed in the present draft legislation, which envisages their removal within three years of the act entering into force. An additional guideline for privatisation of the industry is to ensure the participation of Filipino citizens and corporations.

Under the proposed reforms, generation will be undertaken in future predominantly by IPPs, based on market signals. The government plans to retain a controlling interest over hydro and geothermal generation, as required for national patrimony and by the constitution, but the remainder of the NPC's generation and transmission assets will be privatised.

Transmission will be the responsibility of an independent National Transmission Company (NTC), which will serve as a common carrier for electricity from generators to distributors and large industrial customers. It will despatch all generating plants connected to the system according to a set of market rules. Partial privatisation of the NTC will be achieved by allowing the entry of a strategic partner.

Electrification of isolated small islands and remote areas where private investment may not be economically viable, and other unavoidable social obligations, will remain with government bodies until such time as appropriate incentives have been established for the private sector to assume responsibility. The DOE will annually update the Philippine Energy Plan and Power Development Program. Projects not backed by private investment but required strategically will also become the responsibility of the government.

Restructuring and Privatisation

Within six months of the reforms being approved, the NPC will form the NTC as a wholly owned subsidiary. This will be a regulated monopoly responsible for grid system management and central despatch of generation. It is expected that for 18

months the NTC will act as the market operator, before the activity becomes independent.

Non-strategic generation assets of the NPC will be allocated to five portfolio generators, two of which will be competing generators on Luzon. The government will retain controlling ownership of indigenous and strategic assets. Missionary generation will be undertaken by a separate state-owned corporation.

Within one year, the DOE will draw up a plan for NTC privatisation within three years. Foreign ownership will be restricted by constitutional limits. This sale will come first to enable the market operator role to be developed prior to the privatisation of generation assets.

Within six months, the DOE will present a plan for the privatisation of generating plants. The privatisation value will be optimised, through sales within three years. At least 70% of generation assets and contracts will be sold. Unsold assets will be retained by a residual NPC generating business.

Market Design and Control

The DOE will establish a market for the sale and purchase of electricity within one year. All generating plants will compete for despatch according to pool rules when market operation commences. The market operator will:

- determine the merit order for economic despatch;
- establish a clearing price;
- administer the market;
- amend rules by action of market members.

The NTC will be independent of the generation and distribution sectors, with no cross-ownership. Transmission and distribution operations will be assessed against performance standards. Distributors will have an obligation to supply in a least-cost manner, and rates will be set by return on capital. The draft bill proposes competition initially for customers taking over 1 MWe. Retail access to competition will occur within three years.

Single company ownership of generation assets will be limited to 30% of national capacity and 40% of a single grid's capacity (i.e. the Luzon, Mindanao or Visayas grids).

Unbundled charges for generation and transmission will appear within six months. Cross-subsidies between islands and between different classes of customers in wheeling charges will be removed within three years.

The role of the regulatory body will be to promulgate rules and regulations to prevent market domination and anti-competitive behaviour. This body will be vested with powers to change the market, suspend its operation and licences, and impose formulated penalties on transgressors.

The regulation of licences, tariffs, the futures market, and competitive activities will be covered by increased powers within the Energy Regulatory Board (ERB). Over recent years the ERB has allowed rates of return of 10% for government-owned utilities and 12% for the NPC and privately owned companies.

2.6.5 Issues

The timescale of almost four years for debate and the redrafting of legislation has raised many issues that will need resolution in due course. Some are points of

disagreement on policy, but most are about the methods and timescales for implementation and the degree of liberalisation that should be in place initially when the generation pool is opened.

The following list is extensive and not in any order of priority. Since these issues are all associated with market design and its implications, the timescales associated with their resolution all tend to be less than three years. The issues are:

- The requirement for a universal levy to cover some or all of the following: repayment of NPC's debts, including stranded costs (proceeds from privatisation of generation companies, with or without debts assigned, will be insufficient to repay the NPC's total debt); rural electrification; the development of indigenous fuel sources; and further grid interconnections.
- How should stranded costs be determined? How should they be recovered and over what transition period?
- Raising finance on a market basis may be difficult outside OECD countries, giving large multinational companies an advantage over smaller Philippine national companies.
- Transmission constraints may fragment the market and make supporting a national market more problematic.
- High tariff rates.
- The need for pricing to reflect costs. Tariffs heavily distorted by subsidies and cross-subsidies will not encourage efficiency or fair competition (this applies to transmission charges and sales tariffs).
- The level of regulatory control. The balance between commercial freedom and over-regulation in the early stages of market operation will affect investment appetite and privatisation valuations.
- How should indigenous energy resources be promoted and defended against competition?
- The valuation and viability of electricity cooperatives will be affected by market introduction. Smaller cooperatives may find competitive trading very tough.
- Wheeling rates.
- Open access.
- Generation and distribution companies cannot own transmission, nor vice versa, but what about generation and distribution in common ownership?
- How is anti-competitive behaviour defined and how is it addressed?
- What should the timetable be for retail competition? How will it be accomplished, and how much will it cost?
- A free-bidding generation pool may not burn the "right" fuels according to the government's fuel policy, and indigenous fuels may be disadvantaged. The national policy on fuel diversity may not be delivered.

2.7 Republic of Korea

2.7.1 Background

Korea imports more than 90% of its energy. High economic growth in the years before 1998 was accompanied by equivalent growth in energy consumption and typically over 10% growth in annual electricity demand. Peak capacity margins in the mid 1990s had fallen to below 10%, but investment in 3–4 GWe of new generation per annum gradually increased this margin. The slump in demand in 1998 resulted in the peak margin jumping to about 30% as construction of new capacity continued. Growth post 1998 has returned to over 10% and annual demand is now 215 TWh with installed capacity of over 45 GWe.

Future investment in new capacity must meet the forecast annual growth of around 6%. To date only 2.5 GWe of generating plant is outside the ownership of the monopoly utility KEPCO, which is 51% government owned and has monopoly roles in transmission, purchasing and distribution.

Energy prices to industry have been subsidised (by as much as 25% for electricity) leading to inefficient consumption which should now be addressed. International environmental agreements will limit future growth unless these inefficiencies are removed. However, the competitive position of exported goods from energy-intensive industries requires energy costs to be as low as possible, to remain competitive with other nearby exporting economies.

The government believes that a reasonable rate of return for the industry should be about 9%, but KEPCO is expected to produce only 5.8% in 2000. In previous years it has produced 3% to 5% return. Tariff increases of around 15% would be required to improve rates of return to 9%. The government holds the power to determine tariffs presently, and also in the future under the plan proposed for the restructuring of the electricity industry.

In November 1999 electricity tariffs were raised less than expected, by an average of 5.3%, leaving expectations of further increases, though whether the government intends to target a specific rate of return for the industry remains unclear. Direct prices to end users in the housing and agriculture sectors were held, to avoid any inflationary impact on the electorate. Current tariffs compared to the average are: commercial 144%, housing 129%, education 119%, street lighting 87%, industrial 78%, and agriculture 58%.

The commercial sector, which includes businesses and hotels, cross-subsidises all others, with agriculture the main beneficiary and with the industry sector also benefiting. Certainly one would expect the delivered cost in increasing order to be industrial, commercial, education, street lighting, housing and finally agriculture. Thus, the policy of supporting primary producing and exporting sectors has dramatically distorted electricity charges from their associated costs.

Years of investing to meet demand growth, together with revenues which were insufficient to cover investment costs, has resulted in KEPCO being heavily indebted. The company's 1999 financial position was:

- Debt: US\$26.2 billion.
- Capital: US\$15.0 billion.
- Income: US\$12.2 billion.

- Costs (inc. taxes): US\$11.3 billion.
- Net profit: US\$0.9 billion.

Historical Drivers for Change

In order not to constrain economic growth, investment in new capacity has been made to meet growing electricity demand. However, this investment could not continue to be made by KEPCO without large price rises.

The entry of private investment into the generation industry has already been allowed, and KEPCO itself is partially privately owned. However, all power produced by others is purchased by KEPCO. With the level of debt carried by KEPCO, structural change to encourage increased private funding and to reduce the debt is needed urgently. Post 1998 the government began to look for means by which the private sector could take more of the exchange rate risk of servicing foreign debt incurred in future and existing investments.

Government Policy and Objectives

Faced with significant growth in the consumption of energy, almost all of which will continue to be imported, together with its inefficient use, the government decided to address the fundamental and structural problems of the economy. To run the economy, the Ministry of Commerce, Industry and Energy has adopted the principles of transparency, competition and economic freedom.

As a major importer of energy and fuel and an exporter of manufactured products, Korea needs to purchase its fuel at competitive prices and to convert this into low-priced electricity to maximise revenues into the country from exported goods.

To reduce debt in its industrial enterprises the government has followed a policy of privatisation. Gas and telecommunications companies have already been privatised, and the government proposes to follow with KEPCO, with generating assets to be sold first.

The specific objective is to reduce the debt to capital ratio of KEPCO from 175% at present, by exchanging continual borrowing for private sector investment. It is expected that privatisation proceeds will be used to reduce government debt within KEPCO rather than for other purposes, such as paying dividends.

Applied to the power industry the two main principles of government industrial policy become competition and privatisation. The main purpose of reform is the expected gain in financial and operational efficiency, together with resources from other sectors.

2.7.2 Liberalisation Progress

In 1998 the government announced the future privatisation of KEPCO, now 51% state owned. It is a near-monopoly generator, with 94% of 1999 generating capacity, with a monopoly on transmission. It is the single buyer for power from other generators, and is the sole distribution company.

The government issued a restructuring plan for the electricity industry in 1999. This proposes the phased introduction of a competitive wholesale market leading to full retail competition after 2009.

2.7.3 Current Objectives

The short-term objectives for the electricity sector are:

- To maximise the valuation of KEPCO's generation assets on privatisation. That is, to maximise the cash proceeds and minimise the remaining liabilities and stranded costs.
- To improve business efficiency in generation by introducing competition, in regard to over-capacity (down to 15% by 2001), fuel purchasing, and construction and maintenance costs.

In the longer term, the objectives are:

- To ensure a reliable and inexpensive supply of electricity. (Since it is an owner, a regulator of prices and a collector of taxes, the drivers on government will remain confused, though this will become less so as privatisation proceeds. The current structure appears to need price increases, however the introduction of competition may change this.)
- To eliminate cross-subsidies resulting in distortions in pricing. (Distortions within the main consumption sectors will result in distorted competition and efficiency losses that will become more onerous to remove after a few years of significant growth.)
- To improve customer satisfaction with services. (In particular this requires a reduction in the current bureaucracy of dealing with a monopoly, by the introduction of choice through competition.)
- To create a distribution and supply structure which is successful in delivering inexpensive electricity.

2.7.4 Proposed Programme of Change

At the end of 1999 the government's restructuring proposals were as follows:

Phase I (by 2000)

Restructuring. KEPCO will restructure its generation into five non-nuclear subsidiary "GENCO" companies, each with capacity of 7.5–8.0 GWe, together with a nuclear subsidiary of almost 13 GWe.

Phase II (2000–02)

Restructuring. The market and system operator will be created, initially as a subsidiary of KEPCO. However, it will operate as an independent entity, separate from KEPCO and the GENCOs. Its major decisions will be made at a general assembly of its members, the market participants.

Towards the end of this phase distribution assets will be transferred to regional subsidiaries, which will purchase electricity from a pool.

Privatisation. During this phase the non-nuclear subsidiaries will begin to be privatised one at a time. The holding to be retained by the government and the associated share of debt for each company remain to be determined.

Market design. Generators will bid into a cost-based generation pool based on approved avoidable costs for four seasonal periods. Day ahead, availability and technical information will be submitted on an hourly basis. The marginal price will come from an unconstrained schedule.

KEPCO, as single buyer, will purchase the required energy based on the marginal cost. Independent producers with existing power purchase contracts with KEPCO will continue to be paid on those terms until contract expiry. Fixed costs will be paid separately by KEPCO.

The Korean pool will be mandatory for generators. However, in early 2001 generators will be permitted on a limited basis to sell directly to large customers by using contracts for differences. Around mid 2001 the pool will commence to be based on competitively bid prices.

Control. An independent regulatory agency will be created.

Phase III (2003–09)

Privatisation. The regional distribution companies will be privatised.

Market structure. Wholesale competition will commence with individual distributors purchasing from the pool. The generators will be allowed to sell to distribution companies and to qualifying customers directly, and self-despatch their plant upon notification to the system operator. The range of customers for direct supply will be enlarged, in preparation for retail competition after 2009.

2.7.5 Issues

The major issues surrounding the government's liberalisation plan include:

- Trade union opposition to restructuring changes must be managed in order to obtain legislative approval. Union proposals involve the government retaining control of spun-off generating companies by continued ownership at 51%.
- Low end-user tariffs, which if raised prior to privatisation may enhance the value realised on generation asset sales, but may provoke objections from customers expecting price reductions with liberalisation.
- Rates of return will be influenced by those allowed by the government for KEPCO as a single buyer distribution business until Phase III, and as a generator. The new generating companies will sell initially to KEPCO, whose tariffs to customers will be determined by the government to provide a reasonable return for KEPCO. KEPCO will have no ongoing responsibility for the debts of the new generators.
- Subsidies are commonplace and tend to limit the efficiency that can be reached with any market proposal. There are cross-subsidies in end-user tariffs that will cause a consumer backlash when unrolled. The government will gradually take up responsibility for non-market services and will require levies to pay for certain debts and to support certain uneconomic developments. KEPCO currently supports, via subsidies, the LNG, domestic coal and nuclear industries, and hence gradual removal of these subsidies will impact on the government's fuel mix policy, which may change.
- A capacity plan will continue to be coordinated by the government to meet demand on the basis of construction plans put forward by generation companies. Therefore the market may still be managed. New capacity may need incentives in a high demand growth environment if the market design and industry structure causes low profitability.
- Should the power pool be simple, or specific and hence complicated?

2.8 Taiwan, China

2.8.1 Background

The island of Taiwan imports around 97% of its energy. Efficient use of fuel is therefore important, and sufficient power is equally fundamental to underpin growth in the economy. Recent high demand growth in electricity, associated with high GDP growth, has not been matched by new capacity construction. The island is heavily populated and its electricity grid is not linked to mainland China. In 1985 there was a 55% margin in spare capacity but by 1992 this had fallen to below 5%, and it was still below 11% in 1999. Peak demand is now approximately 24 GWe, which means that whenever a generating unit over 1 GWe breaks down, power rationing occurs. Line outages in July 1999, and again following the earthquake of September 1999, have demonstrated the need to hold more reserve distributed across the island.

One of the issues for Taiwan is therefore the failure to build sufficient new capacity in time. With recent increases in the total demand of 155 TWh being around the 8–10% level, investment in new capacity is one of the key challenges. Land procurement, prices and wayleaves, and approval procedures and requirements on foreign investment, are among the problems. Of the first 11 independent power producer (IPP) projects, only three had started construction by 1999 and only one of these had reached commercial operation. Environmental Impact Assessment (EIA) approval had been achieved by eight projects, while seven had signed a power purchase agreement with the Taiwan Power Company (Taipower), the vertically integrated state-owned utility. However, two of these agreements were subsequently terminated due to non-payment of the contract security.

Despite the above difficulties in the construction sector, Taiwan today has an excellent diversified mix of generation plant types, helping it to manage fuel costs, if sufficient spare capacity can be achieved. At the beginning of 1999 the generation mix was 15% LNG, 17% hydro, 19% oil, 19% nuclear and 30% coal. A significant factor in delivering objectives on fuel mix, efficient power pricing and lower emissions is the use of LNG, which has to be imported and is twice the cost of natural gas on mainland China. To encourage a reduction in carbon dioxide emissions, the government has provided incentives for LNG-fired power plant, which increases the conflict between environmental protection and liberalisation.

A substantial obstacle to private investment could be the rates of return achievable in the liberalised market that may emerge in the coming years. Tariff prices have remained almost constant for many years and at levels that have provided Taipower a rate of return in recent years below 5%. The government has repeatedly refused requests for price increases, and the continued price regulation of Taipower may be seen as a severe risk to private investors in the merchant market environment that the government seems to be moving towards.

Over the next 10 years it is forecast that peak demand will increase by an average of about 5% to almost 43 GWe, and that average demand will rise by about 4.5%, requiring the construction of a further 27 GWe if a reserve margin of 15–20% is to be maintained. Encouraging the necessary investment will be the important challenge.

Under Taipower's new licence, its generation rights are limited to its existing plants. The Ministry of Economic Affairs (MOEA) may grant new rights to other generators on a case-by-case basis. IPPs must sell to Taipower, which retains monopoly rights in transmission and distribution until the Electricity Act is amended, which it may be soon.

If the proposed Electricity Act becomes legislation then this will divide the industry into the segments of generation, transmission and distribution, with only Taipower remaining as a vertically integrated company. Private investors will be allowed to enter any or all of these sectors. However the new cabinet has concerns over nuclear power and the Legislative Yuan has asked for an Energy Act to be drafted to gain consensus on energy policy. The result is that the privatisation programme for Taipower and other electricity deregulation is likely to be delayed.

Historical Drivers for Change

To deliver the large increase needed in generation, together with reinforcement of the transmission system, will require a very significant investment from foreign sources. This must be attracted to Taiwan, but at the same time the government would prefer in future to avoid taking the financial risk of long-term contracts, which may become onerous over time. To be successful in this requires a suitable investment environment to be developed.

Government Policy and Objectives

The MOEA has a policy of opening industry to private investment. For the electricity industry, its aims are:

- a competitive business environment;
- a stable electricity market;
- power liberalisation, initially through restructuring and privatisation;
- mitigation of obstacles to open access.

2.8.2 Liberalisation Progress

The current Electricity Act was promulgated in 1954. Over recent years it has been shown to be inadequate. In 1994 the MOEA produced documents entitled *Operational Guidelines for Unbundling the Power Generation Industry*, and *Main Points in Handling Independent Power Programme*. These were intended to promote and publicise operating standards for independent power production. In 1995, *Application Guidelines for Establishing IPPs* was published to assist with procedures and in the review of applications. The MOEA drew up a six-year power purchase plan designed to double capacity by 2002, with IPPs producing 30% of generation and a reserve margin of 20%.

Also in 1995, to promote liberalisation, the Executive Yuan submitted a draft amendment to the Electricity Act. However, this did not complete its first review procedure in Congress and by 1999 these proposals were outdated and were turned back for redrafting.

During 1995 the MOEA granted permission for IPPs totalling 10.3 GWe to be developed with planned commercial operation from 1998 to 2002. In practice, the first did not reach commercial operation until mid 1999. The output of these stations will be sold to Taipower under 25-year power purchase agreements.

One of the conclusions drawn from a development conference of all major political parties in 1996 was that state-owned companies such as Taipower should be privatised before 2001.

In February 1998, Taipower's original licence expired, to be replaced by one amended to recognise that generation, transmission and distribution rights can be granted separately. Generation was already opening up with the IPP programme.

In January 1999 another IPP programme was announced to encourage further LNG capacity of about 2.8 GWe. A project qualified if it satisfied six conditions:

- The developer had acquired the land or the agreement of the landowner.
- The project had EIA approval.
- The connection plan had been reviewed and agreed by Taipower.
- Opinions on the construction plan had been obtained from Taipower.
- The Chinese Petroleum Corporation or the future LNG supplier had agreed to supply LNG.
- Bank agreement for project financing had been secured.

According to MOEA instructions, Taipower sets tariffs for purchasing power from IPPs. At the IPP's scheduled completion date, if forecast reserve margin is less than 20% then the IPP can get a capacity charge in addition to the energy charge. If reserve margin is higher than 20% then there will be no capacity charge. This programme is valid until either Taipower achieves privatisation or the Electricity Act is amended, whichever is earlier.

During 1999 and 2000 Taipower faced significant challenges that it had not previously experienced. In 1999 there were serious blackouts followed by a severe earthquake that demonstrated the need for more reserve and additional security on the transmission system.

In December 1999 the Executive Yuan completed its review of the draft Electricity Act and proposed it to the Legislative Yuan. However, due to the transition to a new cabinet, the Act was not discussed until September 2000. The expressed intention of the new cabinet to terminate the construction of the Fourth Nuclear Power Plant Project dominated the discussions, and led to disputes between the ruling party and the audit authorities. Consequently little progress was made on electricity deregulation during 2000.

In February 2001 agreement was reached between the Executive Yuan and the Legislative Yuan included the resumption of the fourth Nuclear Power Plant Project, after delay of 110 days. One of the conditions of the letter of agreement was that the Executive Yuan will draft an Energy Act aimed at bringing consensus to energy policy. It is likely that the further deregulation of the electricity sector may be delayed, while a consensus is developed on energy policy.

2.8.3 Current Objectives

To open up private investment opportunities and enable funds to be more easily obtained the government had proposed in 1999 to pass new legislation in 2000 to improve the investment environment, restructure the industry and privatise the state electricity utility Taipower. By early 2001 this had not happened for the reasons explained above. However, specific short-term objectives must include:

- To clarify procedures for project approval.
- To achieve future investment with private funds.

- To restructure the electricity industry into separate generation, transmission and distribution companies.
- To introduce open access and enable independent producers to sell direct to customers.
- To privatise Taipower to raise funds for other public infrastructure projects.
- To achieve a reserve capacity margin of 20% as soon as possible.

To date the government has imposed long-term energy policies through Taipower, and although these policies will not change their implementation may need to be reviewed post-privatisation. Such policies include:

- Safeguarding the security and quality of power supply, in a competitive market that delivers operational and financial efficiency.
- Promoting high efficiency and clean generation, including small hydro and renewable energy schemes.

One would also expect to see new policies emerge on some of Taipower's current responsibilities, such as:

- Cross-subsidies in electricity prices to be removed.
- Social responsibilities to be taken over by government departments.
- Continued responsibility for nuclear plant operation.

2.8.4 Proposed Programme of Change

Restructuring

The purpose of the proposed Electricity Act is to divide the industry into the three segments of generation, transmission and distribution, though Taipower may be allowed to remain as a vertically integrated company. None of these sectors will be monopolies by right, since private investment is being sought in all sectors. The draft amendments permit similar companies to operate in the same geographic area.

Generation prices will not be controlled and IPPs and self-generators will be able to sell their output directly to:

- identified users via wheeling;
- identified users via a constructed transmission line;
- regulated power generation, distribution or vertically integrated companies.

Initially it is expected that the identified users will be large customers, possibly those above 161 kV.

Privatisation

The government has decided that the privatisation of Taipower will await the completion of the Electricity Act amendment. The proposal outlined at the end of 1999 was for Taipower to be privatised as a single vertically integrated company in three phases.

The bulk of government-owned stock (MOEA owns 66.72%) will be sold in three phases over the period to mid June 2001. This breaks down as: ~10% to employees and domestic investors in Phase I; ~10% to employees and foreign investors in Phase II; 30–40% to employees and citizens in Phase III. This indicates a MOEA retention of at least 5%. Almost 30% of Taipower is currently owned by the Taiwan Provincial Government, which will retain its holding. Thus,

private ownership after Phase III will be less than 70%, and less than 9% will be held by foreign investors. Government ownership will remain above 30% in order to ensure a stable power supply.

The delays to the Electricity Act and the call for an Energy Act must indicate that the original target dates set for Taipower privatisation around 2002 will not be achieved. The Ministry of Economic Affairs set a tentative target for the privatisation in 2005, which may be realistic.

Market Design Features

The draft proposed market structure provides for a transition period, expected to be about two years, in which an independent organisation will ensure the impartial scheduling of generation plant and operation of the grid system. This organisation will have no vested interest in the outcome of prices in the energy market. The current power purchase contracts of IPPs will continue, with Taipower effectively remaining the single buyer. However, large customers will be allowed to purchase power from co-generation and renewables.

In the liberalised market the role of the independent organisation will be expanded to include the functions of power exchange, system operation and demand forecasting. Generators, including Taipower plants, will bid into a power pool to sell their energy.

New IPPs will be allowed to choose their own customers, presumably starting with the largest first, and transmission companies will be required to carry the energy. Taipower's share of purchases as the original single buyer will start to fall as production volumes increase, but Taipower will need to compete to sell the volumes it has already contracted to buy.

Control

The proposed Electricity Act amendments divide the industry into private producers and a public utility sector (i.e. transmission, distribution and vertically integrated utilities such as Taipower). For the latter group, prices will be regulated by a commission.

Regulation of the prices offered by Taipower to end users will provide a means of controlling prices, because private producers will be competing to capture customers. This could in turn influence the rates of return that can be achieved in the market.

The Council for Economic Planning and Development has stated that:

- It supports the above timetable and agrees to the plan in principle.
- The MOEA should outline its liberalisation policy on the electricity industry and it should be incorporated with Taipower's privatisation plan after approval by the Executive Yuan.
- The timetables for the flotation of the two largest state-owned enterprises (Chinese Petroleum Corporation and Taipower) must avoid an unfavourable impact on the capital market.
- Concessions offered by Taipower through cross-subsidies in electricity prices should be eliminated.
- Disadvantaged groups must become the responsibility of the relevant government organisations.

- Nuclear, because of its financial risks, and hydro, because of its multiple applications, should remain state owned.

2.8.5 Issues

The main issues concerning the electricity industry in Taiwan include:

- The current inadequate capacity margin.
- The difficulty in securing private project approval and subsequently progressing the project to commissioning.
- Tariff prices that the government is reluctant to see rise to give acceptable returns for private investment.
- The government's desire to see the private sector pick up all the market risk.

Other issues to be addressed include those that arise from the conflict between an energy policy solution and a free market solution. These include:

- The high cost of LNG and the need for overseas transportation, storage and pipeline facilities limit the use of gas as a low-cost entrant fuel for the electricity market that brings with it environmental improvements. Incentives are considered necessary by the government.
- Hydro plant reservoirs are used for irrigation, flood prevention and scenic beauty, as well as generation. The government is considering retaining ownership since it believes proper regulation secured by legislation is necessary.
- There appears to be little potential for reduction in electricity prices. Taiwan maintains cheap prices to customers and has not raised these for 15 years. The current rate of return is below 5% but the government has repeatedly rejected requests for price rises. Observation of electricity liberalisation in other countries shows that customers expect price reductions. Can the reliability level be improved and sufficient private investment encouraged to meet the required growth, together with future price reductions?
- With Taiwan being densely populated, the construction of new transmission and distribution lines is increasingly difficult. A new transmission trunk is required for south to north flow of power, and the loss of single lines can cause significant losses (e.g. 80% Taiwan was blacked out in July 1999, with only 10 out of 200 generating units still operating). The problem of local monopoly positions of generators, as well as more frequent energy shortages caused by low reserve margins in a liberalised market, must be solved.

2.9 Thailand

2.9.1 Background

Since the mid 1980s Thailand has had one of the most rapidly growing economies in the Asia-Pacific region, with growth rates in GDP nearing 10%. Over the same period the growth in electricity consumption averaged over 13%. However, economic growth slowed to a standstill in 1998 and growth in electricity consumption has been zero between 1997 and 1998.

Thailand borders Cambodia, Laos, Myanmar and Malaysia, and trades electricity with the latter three countries. There are agreements to expand electricity trade to the equivalent of over 6 GWe of capacity by 2005. With Thailand being the largest market for electricity in this area, inter-country trading is a vehicle to promote mutual cooperation in the Mekong Delta region.

Thailand imports the bulk of its energy consumption and, while increasing its production of indigenous energy, it will continue to rely on imports, particularly coal, for the foreseeable future. With total electricity demand around 93 TWh and growth rates expected to recover to around 6–8%, efficiency in procurement, pricing and consumption is clearly important.

Policy commences at the top with the National Energy Policy Council chaired by the Prime Minister. This can be considered as the current regulator for electricity, using a cost of service form of control. This may be considered to have worked satisfactorily, with reasonable efficiency and a lack of power shortages. Thailand ranks high among developing Asian countries in electrical distribution standards, and both transmission and distribution losses are comparatively low.

The current electricity industry structure is essentially a state-owned generation and monopoly transmission company, the Energy Generating Authority of Thailand (EGAT), selling wholesale to two state-owned distribution companies, the Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA). The generation sector has seen some liberalising reform with the introduction of IPPs, small power producers (SPPs) (e.g. co-generation and renewables), a partially privatised subsidiary of EGAT, and interconnections into Laos and Malaysia. All these sell power to EGAT Generation as single buyer, although some of the SPPs sell directly to customers.

The fact that Thailand successfully managed its electricity requirements during the rapid growth years up to the mid 1990s has resulted in an over-capacity, as a result of the unexpected slump in 1997–98. Excess generating capacity already committed is more than sufficient to meet expected peak demand until about 2007. With sufficient gas resources in the short term, the continued growth of combined cycle gas turbines (CCGTs) is to be expected, since new capacity will be needed later. However, forecasts also predict a requirement for a significant increase in imported coal.

The public has welcomed liberalisation in general, with increased competition and the opportunity for lower prices. Over 98% of Thailand's villages are already electrified, so rural electrification is no longer a key issue. The remaining issue here is the provision of higher quality services. Economic growth over the last decade has resulted in a large number of middle income earners that find electricity prices affordable at around US\$0.05/kWh.

This level of pricing has also been sufficient to maintain financial viability, with rates of return in the state companies probably in the range 6–8%. Consequently prices to date have not been an issue. For social equity considerations the government charges a uniform retail price throughout the country, with residential and industrial customers paying similar prices. There are therefore significant cross-subsidies between the industrial and the residential sectors, and also between the MEA and the PEA. Subsidies to industry ended in 1990, except for those in industrial parks outside Bangkok that receive a 10% discount.

Historical Drivers for Change

Thailand has shown that it can manage rapid growth rates in electricity demand of over 13% per annum, with prices which are acceptable to customers. The current drivers are to manage the short-term excess capacity until 2007, and to transfer the requirement for future funding from the government to the private sector.

Government Policy and Objectives

In 1992, Prime Minister Chuan Leekpai came to office promising reform of the state economy. The government passed a master plan for reforming the state enterprise sector that provides a framework for restructuring and privatising certain sectors, including energy.

The government's policy for energy sector liberalisation is:

- To increase the efficiency of the sector's utilities.
- To reduce government involvement in the operation of utilities.
- To increase competition.

Specific objectives in achieving the above are:

- To ensure energy availability.
- To encourage private investment.
- To promote free market competition.
- To implement energy conservation.
- To reduce the environmental impact.

2.9.2 Liberalisation Progress

The electricity industry in Thailand is dominated by three state-owned utilities (EGAT, MEA and PEA). EGAT was created by the EGAT Act of 1968. It has sole responsibility for transmission and selling bulk electricity to MEA and PEA. MEA is responsible for distribution in Bangkok and two neighbouring provinces, and PEA is responsible for distribution elsewhere. Until 1992 EGAT had sole responsibility for generation.

A 1988 government report recommended that 41 of the 61 state enterprises should be privatised by 2001. To encourage commercialisation, in preparation for privatisation, the government created a new class of enterprise, known as "Class A", which benefited from salary scales no longer linked to civil service schemes and from less ministerial control. One of the requirements to gain Class A status was to achieve rates of return higher than 6%.

In 1992, the government established the National Energy Policy Council (NEPC). It also passed a master plan for state enterprise sector reform, which provided a framework for restructuring and privatisation of certain sectors, including energy. The EGAT Act was amended to end EGAT's monopoly on generation and to

permit the private production and sale of electricity. NEPC was responsible for the implementation of the IPP programme, and also that for SPPs, which focused on renewables and co-generation. To restructure and commence preparation for privatisation, EGAT set up a wholly owned subsidiary generating company (EGCO) that would generate power and sell it to EGAT.

In 1994 EGAT gained Class A ranking for state enterprises, which enabled it to contract directly with others for the sale of electricity, the purchase of fuel, and also the purchase of electricity from IPPs and from other countries. In 1995 the government gave approval in principle for the privatisation of PEA. The plan was for regional decentralisation into corporatised subsidiaries.

In 1996 the government approved EGAT's proposal to privatise its subsidiaries when appropriate, while EGAT continued its existing responsibilities, thus avoiding the need to change the law. The master plan for EGAT's privatisation was approved. In 1997, Thailand signed a memorandum of understanding with neighbouring Myanmar to purchase electricity over the following 10 years.

2.9.3 Current Objectives

The main short-term objective of the liberalisation and privatisation of the electricity sector is to reduce government investment and public sector debt. Hence maximisation of asset values and debt reduction are required.

In the longer term, the objectives are:

- To further develop the capital market.
 - To continue to encourage private investment, to allow sales of state utilities.
 - To increase competition.
 - To improve efficiency in management and use of power and energy resources, using long-term purchases from Laos and Malaysia, and demand management at home.
 - To restructure tariffs to reflect marginal costs.
 - To provide consumers with improved services, prices and safety standards.
- Hence lower tariffs for consumers is a requirement.

2.9.4 Proposed Programme of Change

The master plan outlines three stages for electricity liberalisation:

Stage I (until 2001)

Restructuring. EGAT remains the primary power purchaser and provider. It will be corporatised as a single entity, with autonomous business units acting as profit centres. PEA will be decentralised into four businesses.

Privatisation. The Ratchaburi power plants will be privatised.

Control. Regulatory control will be established to ensure non-discrimination in despatch of generation by EGAT's transmission division.

Stage II (2001–03)

EGAT (and MEA and PEA) will gradually introduce wheeling access for other power producers to sell direct to consumers.

Stage III (post 2003)

Market design. A competitive wholesale power pool together with retail competition will be considered. The long-term structure will be a competitive generation pool, as well as bilateral contracts between generators and major customers.

Control. An independent system operator will oversee competition in generation. Transmission will be owned by a company separate from the system operator. A national regulator will oversee transmission, open access and reasonable tariffs. It will also regulate the regional distribution companies to ensure access and set tariffs. Retail supply may be undertaken by the distributors and independent suppliers.

Post 2004. It is envisaged that EGAT generation will be divided into several companies and privatised, though there is debate about the hydro assets. The sizes of these portfolio companies could vary from 5–10 GWe.

2.9.5 Issues

The following issues have arisen in debate mainly between the government and EGAT:

- Independence of the system operator from transmission.
- Independent ownership of hydro plants, and disputes over water ownership rights.
- Stranded costs are significant and the period and method of recovery requires resolution.
- Power purchase agreements with IPPs continue for many years and their treatment, particularly in pool bidding, requires resolution.
- The large workforce and strong labour unions require acceptable management. Failure in this area could derail the whole privatisation programme.
- Generation companies are likely to be single station IPPs and a few portfolio companies emerging from EGAT, who will have advantages over other companies in operating in a pool bidding market.

3. OBJECTIVES AND CRITERIA

Following from the plans laid out in Chapter 2, the eight electricity-specific objectives chosen by the Steering Committee (section 1.4), and some practical criteria that may be used to test the success of actions taken to address these objectives, are discussed below.

3.1 To Introduce Competition in Generation

The introduction of competition in generation has widespread support, with the overall general aim of reducing prices in the construction and operation phases of generation. The beneficiaries would therefore primarily be the consumers of electricity in terms of reduced costs. This should also yield increased profits in energy intensive manufacturing companies, which will thus contribute more in taxes to the state. The government may also gain in several ways through other associated actions, such as privatisation, reduced state operating and investment costs, the ability to control generation without funding it, and improved relations with the electorate due to reduced prices. The "cost" to the government is loss of the ability to raise direct income through electricity revenues.

The main losers through competition are the incumbent electricity generators, who will see prices fall with time. To date circumstances have been such that market introduction has led to reduced prices paid to generators. However, there are markets where current prices are below the costs of new entrants, and demand in future will require this higher cost generation to be built. This is the situation in many US states, where new build to meet peak demand has been delayed because the price of gas-fired generation (the most likely new build) would be higher than that of existing coal plants. Current wholesale electricity prices near US\$20/MWh would need to rise towards US\$28/MWh in some states to pay for new gas plants.

When new entrant prices are higher than existing prices, customers will resist paying higher prices. As shortages commence in a relatively open market, prices will become more volatile with high peak prices. Customers exposed to these prices will eventually contract for new capacity, though the process usually lags the need to meet demand. Alternatively, signals to build new capacity can be incorporated either within the market rules using a specific capacity payment element, or within power purchase agreements by including availability payments. Both of these smooth the natural market volatility and encourage earlier construction. The situation is not the same in Western Europe, where gas plants will reduce electricity prices. Consequently, the introduction of competition in Western Europe is accompanied by expected falls in prices and thus strong support from the electorate for change, but by opposition from power companies.

The following requirements are seen by the Study Coordinator as essential tests to determine the degree of competition, with associated downward pressure on future prices, that is likely to occur if a competitive bidding market is introduced in generation. Forecast electricity prices over the next 5–10 years are used for many purposes, such as the valuation of assets, decisions on debt reduction and investment, and deciding how to pay for and hence achieve the other objectives.

For competition in generation to have most benefit, the market must:

1. **Need lower consumer prices.** Lower prices can quickly result from aggressive competition. If for some reason, such as to pay debts, to attract investment in new capacity, or to cross-subsidise other investment, prices need to be kept high then there are simpler ways than competition to deliver the appropriate price profile. However, any economy that is a major exporter of manufactured goods may benefit enormously from lower prices, to remain as competitive as possible against other exporting economies.
2. **Have an attractive investment environment.** Competition relies on there being excess production over demand. Therefore the excess capacity must be constructed in the near future and must be maintained. If prices are to be reduced, it is important that existing high cost production is replaced by new, lower cost production. This is fundamental to the success of competition.
3. **Have high prices now, in generation and also in supply.** This point is fairly self-evident. If the end prices to customers are near or below the production costs of the lowest cost technology, then the introduction of competition, which is by any measure expensive, cannot be cost beneficial. Whether or not generation prices are high compared with the costs of new entrant plant, particularly gas-fired, is a key driver for competition. If gas plant is lower cost than existing plant then this is an enormous advantage (as is the case in Western Europe, for example).
4. **Have easy access to the transmission grid.** Applications, licences and approvals must be simple and quickly addressed. Contracts with the transmission company must not present a barrier in terms of standards of connection, and requirements for back-up supplies to fulfil power purchase contract terms must not be onerous.
5. **Have excess capacity in generation.** Competition is fundamentally one producer winning a bid to operate, thus preventing another producer from doing so. It can be defined more precisely than a simple excess of supply over demand. Generation companies may own more than one station. Ideally, the excess capacity over demand should be more than the size of the largest company. Otherwise this company must operate to some output level and under competitive price setting could set high prices.
6. **Have a well interconnected transmission grid.** Ideally there should be only minor transmission constraints. To have none would imply excess investment in transmission. However, if constraints exist, generation plant behind such constraints can in principle bid high prices and achieve them. Constraints can prevent other plant from bidding lower to prevent high priced plant from operating. Large constraints, where the ability to transmit power is small compared to demand levels, will fragment a grid into different competitive zones (i.e. several markets).
7. **Have many competitors.** It is a fallacy that the requirement for adequate competition is anything so simple as five or six generating companies. Clearly this enhances competition, but electricity is probably the most complex of commodities (if indeed it is a commodity). Guidelines are that excess capacity in a well interconnected grid only needs to be about 20%, and this should exceed the size of every generating company. Price setting using system marginal pricing is limited to marginal generating plants, and hence there need to be several of these (more than five). Since price setting occurs throughout the full demand range, there need to be competitors at every demand level.

An assumption in most theoretical analyses is that the generating companies have similar cost structures. However, this is rarely true in reality and production cost differences limit competition. A guide for aggressive competition is probably that no company exceeds 10% of total capacity. However, it is possible to analyse a particular mix of generation and market structure to determine which companies will compete and which will not. Mutually beneficial price bidding between some companies will be realised if these companies conduct the appropriate analysis, or possibly by trial and error, without any resort to collusive action.

Failure in any one of the above checklist of criteria or requirements can negate any benefits arising from a market based on competitive bidding to operate and to set prices and hence alternative measures are likely to be more successful. The Study Coordinator considers that there are perhaps only two markets where the prime requirements, in particular a sufficient number of competing generators, are favourable enough to cause aggressive competition.

The first is Argentina, where there is a large number of single power station companies that would compete aggressively within any form of bidding market. The risks here are high and the profits low, so that companies are beginning to merge and vertically integrate to remain viable. Half of production is from hydro, and gas is the new entrant with already over 30% market share.

The second was the state of Victoria in Australia before the market was extended to include New South Wales. This market had several favourable features for competition. It too had single power station companies, all of which burnt brown coal and hence had similar costs. However, here the new entrant price of gas was higher than current brown coal production. Even with several favourable features, additional incentives had to be introduced to cause market price reductions. These included the sale of generation plant with contracted output higher than would be expected from its generation volume. A consequence was that such generators had a profit maximising strategy that included the lowering of pool prices.

Electricity Market Profile	Generation/ Supply	Yes or No
Does the market need lower consumer prices?		Yes/No
Does it have an attractive investment environment?		Yes/No
Does it have high prices?	Generation: Supply:	Yes/No Yes/No
Is there easy access to the grid/market place?	Generation: Supply:	Yes/No Yes/No
Is there excess capacity in generation?		Yes/No
Is the transmission grid system well interconnected?		Yes/No
Are there many competitors?	Generation: Supply:	Yes/No Yes/No
Have other market-specific requirements been satisfied?		Yes/No

The previous logic can be captured in a profile of a country, state or proposed grid area, set out in a pro-forma table (shown above). Such profiles are included in Appendix 3.

A “No” against any of these requirements could prevent a competitive generation market from delivering cost benefits to the industry. Consequently, either these requirements must be met first, or it must be recognised that a less than satisfactory position will result. This understanding is important when governments are faced with potentially large development and implementation costs that may only partially achieve the desired level of competition.

Practical criteria for the various competitive sectors are discussed below.

3.1.1 Capacity Construction or Divestment

The key criterion is that sufficient new generation capacity is commissioned to meet forecast demand now and in the near future. To achieve acceptable costs for meeting this criterion the elements of competition are to be introduced.

Since construction projects require associated fuel supplies, it can be considered that there should be:

- at least two, but preferably three, different fuel types for strategic/economic security;
- at least two, but preferably three, sources of supply for fossil fuels.

This is to ensure reasonably competitive prices. Some fuel suppliers are state monopolies, which usually means that prices are not closely related to costs. Generating companies should encourage fuel competition, possibly by having access to facilities to import fuel to create competition with an incumbent monopoly.

For project tendering, it is desirable that there should be at least six project consortia to evaluate new construction projects or station divestment sales, and that at least three of these should put forward robust tenders. Similar numbers are required for offering PPAs for the output of competing projects.

Another criteria might be that prices reduce in the following years. This would indicate sufficient competitive pressure in all fuel and construction aspects. Certainly prices increasing with the retail price index is a sign of lack of competition and of inefficiency.

3.1.2 Generation Operation and Market Price Setting

The relationship between the operation of generating units in despatch and the setting of prices in the market varies considerably across the existing markets in the world today. A government should consider its requirements for the two separately before making a decision about how to relate them.

Such separation is similar in principle to setting annual tariffs for consumers while operating the system in real time to criteria other than a true cost merit order. The reason for departing from true costs may be that other factors are included in the merit order, such as labour issues, fuel policy and supply security issues. If these issues are significant then real time pricing may be unrealistic and not worth developing.

The predominant parameter is the timing of pricing and despatch decisions. It is possible to determine electricity prices far in advance, and this is normally

sufficiently accurate for the vast majority of consumers. Prices could be monthly, quarterly, seasonal or annual. Providing that real time prices are not required for more than about 5% of customers then they need not be produced in despatch timescales.

System operators want plant to operate in real time in some economic merit order to reduce the costs of meeting demand. Hence costs and prices are key input parameters. For economic despatch, prices should reflect short-term costs. If the merit order of short-term costs is similar to the order in the tariff or contract prices then there will be little loss of efficiency by using a merit order of prices fixed for a month, quarter or season.

Generation despatch uses many technical parameters that may vary with timescales, but the key parameter is the readiness to operate. This is captured in an availability statement which includes the power level and notice period to start or change. System operators will already have communications systems that allow changes in availability to be notified in real time. Despatch can then be decided on the basis of stability and security of operation instead of setting "spot" prices.

The Study Coordinator considers that, for market price setting, most requirements could be delivered using simple pricing over relatively long period contracts (e.g. seasonal or annual). This does not require complicated, and hence costly, new market software to be implemented.

For generation operation, the Study Coordinator considers that the current communication systems between system operator and power stations for plant availability data (improved if necessary) can be used for despatch purposes. Price information only needs to be updated on the same frequency as contract prices, but availability data will be updated in real time. Because this is not complex data, and only changes from the normal operational data needed to be transmitted, it requires only simple systems.

The relationship between generation operation and market price setting is discussed in detail in section 5.2.

Several countries or areas within the Steering Committee appear to have made the decision to advance beyond the type of market described above, in which a central purchasing agency contracts with the generators for energy for a period of time. A similar effect is produced if generators bid into a simple pool mechanism at the same frequency period. Despatch of electricity production is always done on a real time basis, whether it is self-despatch of plant by the operator or instruction by a system operator. These timescales are therefore very short if captured in market price time periods. The system is much simpler if real time availability information flows are logged as simply as possible consistent with the operation of the commercial contracts in place.

Consideration of this issue can draw on the expertise of those countries and areas that have made decisions to develop their markets further, and also of those that have decided not to at this stage. Criteria for consideration when introducing competition into the price setting and despatch of generation are discussed below.

Market price setting. If any of the following four conditions apply (i.e. if the answer to the question is yes) then the form of the market should include simplifications:

- Is the market price for energy production within a margin of 10% of costs? If a government believes that this is achievable, averaged over the year on a

contractual basis or by another bidding mechanism, then most of the benefits may be achieved by simple means.

- Can less than 5% of industrial demand respond to price signals? If so, then short-term price variations cannot affect demand significantly and it is premature to introduce them into the market. Very simple price setting rules can be used, or contract or tariff prices can be used. Price variation can be provided to large industrial consumers, who may be able to respond through profiled contract terms.
- Do government policies influence more than 10–20% of generation volume? If so, the distortion in the merit order for operation will affect short-term prices calculated from a pool or despatch model.
- Are there significant transmission constraints, affecting more than 5% of total energy payments? If so, the market is likely to be fragmented with local monopolies behind these constraints. Regional markets with rules for transfer flow payments may be suitable.

There are also criteria that are associated with the delivery of fair competition and competitive prices from a short-term despatch or pool algorithm.

If any of the following three criteria are not met (i.e. the answer to the question is no) then the form of the market should include simplifications (indeed, a pool including daily bidding is likely to fail to deliver competitive pricing):

- Is there at least 20% excess capacity over demand for the foreseeable future? Without this, transmission constraints on the ability to compete to generate cannot be overcome. A surplus of below 15% will not produce competitive prices from a despatch or pool type algorithm.
- Is there a large number of competing generators? There should be at least five if almost all generators have similar plants and fuel costs (e.g. Victoria, Norway), and at least 10 if generators have different plants and fuel costs (e.g. Argentina, England & Wales). Market analysis and historical observation both contribute towards these numbers.
- Is the size of each generating company less than the excess capacity? If not, some of the generation of such a company must run and hence receive high bid prices. If the government owns plant that operates within the market, the government may influence prices and also its revenues by increasing operational output.

Generation operation. The overriding criterion for competition in operation is that plant availability must be at least 20–25% in excess of demand. Otherwise plant cannot be prevented from operating through competition.

For well-connected transmission systems it may be possible to operate with a 20% excess, but this is considered low if plant operation can be interrupted. For example, the England & Wales market started with 27% or more spare capacity and a very well-connected grid. Yet even with small transmission constraints, the loss of plants through outages and the loss of gas supplies during gas shortages meant that peak demand was only just met during two winters.

One of the key criteria is therefore that there is at least 20–25% surplus availability over demand. If this is not true there will be little or no competition to operate and a simple cost merit order fixed over a long period may as well be used.

If the rules for setting prices are inconsistent with those for the order of plant operation, then price setting will be distorted as well as plant operation. The degree of simplicity should be reflected in both the despatch rules and the price setting rules. There can be several reasons why inconsistencies between operation and price setting rules occur, besides accidental or known simplifications in one set of rules. The main reason is government energy or environmental policies overruling operation according to the cost merit order rules.

The criteria mentioned above for market price setting on the degree of government policy intervention and on the measure of transmission constraints also apply to distortion in generation operation.

If the following three criteria are not met, it may be difficult to forecast the output of a prospective investment project:

- Are the despatch rules for ordering plant operation transparent and unbiased? In markets where the system operator is not independent there are incentives for the system operator to despatch its own plant. This is common in markets in the early stages of competition and liberalisation.
- Is national or local government-owned plant less than 20% of capacity within any local transmission region? Governments can find many reasons to increase their generation output to the disadvantage of privately owned plant.
- Is the relative economic despatch merit order of commercial plant, compared with other plant operated for security of supply or flood prevention, etc. known prior to major investment? The economic order of merit will usually be qualified by, and subordinate to, first, safety, and secondly, system security, with commercial competition coming third. If the first two priorities are delivered by specific plants then the volume of production for other plant can be very difficult to predict, and can be highly variable from year to year.

3.2 To Introduce Customer Choice

The introduction of customer choice is the natural follow-on to the liberalisation of state monopoly industries. Early privatisations of state assets as single private companies demonstrated that value was gained by the shareholders, rather than by customers. Governments sold control to private monopolies and, apart from gaining privatisation payments, benefits to the state and to the electorate (the customers) were very limited.

Governments would probably have wanted customers to be satisfied with the privatisations, to build electoral support. In general, customers are pleased most by lower prices and better service. These sales were often unsatisfactory in both of these respects. In transferring control to another monopoly, the state is simply deflecting future customer dissatisfaction towards the new owner.

In early electricity privatisations, state electricity industries tended to be split into a very small numbers of companies if at all. Latterly, proposals have been for five or more companies that may compete sometime in the future. The expectation of customers is therefore that prices may be reduced in the future. Restructuring that involves a central purchasing agent selling to local distribution monopolies will not provide choice to customers, and the monopoly aspect does not encourage the improvement of service standards.

Very few markets to date have introduced choice to the customer by developing systems that separate the supply, engineering and billing activities from the local

monopoly distribution businesses. However, such choice, whether or not there is excess capacity in production, will impose additional competition further up the supply chain and eventually onto the generating companies, to encourage price reductions throughout the chain. Choice also allows customers to move to supply companies that provide the best standards of service. Failure by a supplier to give a satisfactory response to a complaint may then result in the loss of the customer. This is usually the key incentive on a supplier.

Once physical distribution businesses are separated from supply to domestic customers the structure of the industry tends to change. Distribution companies join with other utilities to form combined water, gas, electricity and telecommunication companies, and supply companies expand into other products involving regular billing to households. The main purpose is to reduce the costs of supplying customers and to remain competitively priced.

The multi-product distribution company is regulated on its costs and may be benchmarked against others to determine its regulated cost base. It maintains its profits by spreading its costs across more products. Many of these will involve maintenance and installation, which require similar manual skills.

Similarly, multi-product supply companies improve their competitive position by using common systems to bill and read meters across several commodities. Prices for products may even be bundled together, with customer savings increasing with the number of products taken from a single supplier.

Competition among supply companies is aggressive in terms of sales methods and in pricing. It is a low margin business and some companies will become insolvent. Being in the competitive sector, there may or may not be provisions for a customer to be supplied by another supplier if that customer's supplier becomes bankrupt. Hence customers do find cause for complaint in many aspects of supply and choice. These include sales methods, information errors, errors in transfer between suppliers, billing errors and multiple bills.

Once suppliers of electricity are involved with competition for domestic customers, the databases of customer details, meter readings or profiles and billing involve millions of customers and data that may change regularly. The information handling requirements are complex and any problems with these will cause major cash flow problems for low margin companies. For this reason, competition probably only requires four or five major supply companies. Cost reductions are delivered when larger numbers of customers are served by the same central services and databases.

The introduction of choice can take place over a variety of timescales depending upon what is put in place to achieve it. The typical timescale is 8–10 years for pool and installed metering solutions. However, once primary legislation is passed dismantling monopoly supply areas, then it may simply be left to customers and industry to find a way themselves without central systems in place (as happened in Germany), and prices may fall quickly, for example, within a year.

Criteria for the successful start of the development outlined above tend to concentrate on the timing, the possible cost savings that customers may make, and how well prepared customers are to take advantage of change. If the savings are small and bureaucratic to achieve, then customers will not change supplier. Bank charges are probably not competitive, yet how often do customers change the bank that deals with their domestic finances?

Customer awareness of what is a reasonable charge and what savings may be possible are therefore very important for success. The Labour government in the UK has focused strongly on comparing the prices of domestic goods and services with those in other European countries. Clearly, most interest is on where the UK has higher prices rather than lower. Such transparency, and that of company efficiency and profitability, is needed to encourage customers into action.

The prospect of customers changing suppliers is sometimes sufficient to encourage regional vertically integrated utilities to reduce prices. In markets that are electrically well-connected, both internally between utilities and with neighbouring markets, the fear of competition is sometimes sufficient to force utilities to reduce prices, whether it is in generation, transmission and distribution, use of system charges, or supply services (e.g. the UK, Germany).

Criteria for the introduction of customer choice are:

- Costs incurred by a customer to be able to choose an alternative supplier should be less than the expected savings from the change. The investment to take an alternative supply may be around US\$10 000 if half-hourly metering and interfaces to a pool are involved. It may be easy for a very large industrial customer to justify this in terms of expected savings. However, for both small commercial customers and domestic customers it may be prohibitive. Large industrial customers may have efficiency engineers to optimise their use of energy and may even bid generation or demand into a pool.
- A plan outlining the introduction of choice should be made known two years ahead. Choice can encompass many aspects, not just the ability to purchase energy from different providers, although this is clearly the priority initially. Customers can have the choice of purchasing electrical energy, self-supply of electricity, optional membership of the pool, or construction of a direct grid connection. In addition, the following services can be opened up to competition and customer choice: meter supply and installation, meter reading and data acquisition, and supply and billing. This requires the unbundling of production from the distribution businesses, and then the unbundling of all of the service activities from the distribution businesses. Other commodity businesses with related activities are then able to compete and hence provide choice. The development of all these options requires time.
- Restructuring of the industry to provide multiple generators to sell directly, to introduce a pool for wholesale purchasers, to create distribution/supply companies, and to unbundle engineering and service activities should, if necessary, have already have taken place.

To provide choice, there must be multiple providers or options in the relevant activity. Initially, access to spot energy prices through some form of pool may be the only alternative to the state monopoly. However, if wholesalers exist then competition to provide has commenced. The decision to develop a wholesale purchasing mechanism may be simpler than a restructuring of the industry into separate supply businesses. Consequently, although the prices in it may not be sufficiently low to signify competition in generation, a pool allows optional sales and purchases, and hence provides some degree of choice.

The costs of developing central systems for metering and data collection to allow choice in the service activities can be high (US\$1–2 billion). However, if competing systems are developed separately then total costs will be higher. If new

metering is used then the costs may be US\$300 per meter, not including installation costs.

Alternatives to new metering require either the use of existing metering, which is likely to be of a total consumption type, or the use of agreed consumption profiles detailed down to the time period over which competition is to be implemented for that sector of the market.

There are therefore important decisions to be made in segmenting the market into consumption sizes and in determining on what basis consumption will be measured and paid for. Should metered data be used or not, and over what time periods? These decisions should be made on a cost benefit basis, taking account of the expected costs of the required services. These may not be easily available if all costs are bundled together within a bureaucratic state monopoly. Hence the importance of developing a plan, and restructuring on a phased basis so that costs can be assessed with more certainty.

Cost benefit analysis should include consideration of the following:

- The total costs of developing a data management system, including all metering costs for a specific number of customers.
- The total consumption that would benefit in the first year of competition if the above costs were shared across these customers.
- Whether competing distributors/suppliers should develop their own systems or use a central system.

In the plan, demand should be sectorised according to customer size. Political realities suggest that the methods chosen for the introduction of competition within each sector should allow savings to be made within a year. The primary energy market should use time periods which are consistent with metering data collection and the treatment of data for domestic demand.

The positions where voltage steps exist in the distribution system should be considered as appropriate points to divide the market into sectors. Metering with the shortest time resolution can be installed at the first voltage step down from the main transmission system, and also at lower voltage positions, to define the appropriate demand sizes. Individual large customers should be metered separately if they would benefit. By this approach, the size of the first wholesale market can be defined, whereby wholesalers (distributors/suppliers) and large customers can have choice.

Smaller and domestic customers can be sectorised below these voltage levels. Less costly metering or profiling consistent with their required market response times can be introduced later within a phased programme if supported by the cost-benefit analysis.

3.3 To Deal With IPP/Stranded Cost Issues

There are a few key decisions to be made initially in taking account of stranded costs. The industry may have stranded costs held by both state-owned and privately owned industry. The government may recover its own costs over whatever time period it chooses and may even leave them as debt to be recovered through other financial routes. A desirable position for the government would be to be able to introduce competition which reduces prices sufficiently for it to be able to introduce a tax to fund these and other requirements (perhaps

environmental), but which results in lower total prices than before the introduction of competition. The funding and the public relations requirements would then both be achieved.

This "big win" criterion for the government is that debts, stranded costs and other issues are funded within electricity prices, which are in total lower than before the introduction of the initial market.

Of course, this also means that some other sector on which the tax is levied may be less profitable, and this is a risk for investors. The above criterion has not been met frequently, often because long-term investments such as nuclear plant and 25-year contracts for fuel and power cannot be recovered in a short number of years. Governments have typically used around 10 years to recover such costs. Some governments have disguised the issue by raising prices a year or two before market introduction, which also has the benefit of raising the value of assets being privatised, hence increasing government receipts early in the process.

California is an example of how to get many things wrong. The state negotiated stranded costs with its utility companies, which were then to be recovered over the next 10 years through a levy on electricity prices to be applied both to stranded and new capacity. This raised prices significantly, to the annoyance of both customers and new entrant suppliers, who found they could not compete on price with existing utilities. The result is that competition has been prevented and the systems put in place have been problematic. Similar experiences look likely elsewhere in the USA, which is why investors are attracted to buying existing US utilities.

The UK disguised the issue by raising prices in the years just before privatisation. It also removed the existing subsidies to heavy industry over the two years after market introduction, which meant that such companies did not receive price reductions for about three years. Assistance to the state coal industry through pass-through contracts approached US\$1 billion annually, and cost recovery for older nuclear station clean-up was around US\$2 billion annually. Yet the UK managed to produce price reductions for some customer sectors initially, and for all customers during the 1990s. With government ownership of nuclear plants, the UK was not forced to recover the capital investment costs, which is not the case in the USA and Spain, where nuclear plant is owned privately.

To agree the amounts to be recovered by every private company holding stranded costs requires a consistent approach by the government or regulator to all companies. The agreement with each company will be on a financial amount, but the process will include forecasts of electricity and fuel prices, which will differ on each side. A non-contentious process avoiding litigation could require:

- agreement between government and utilities on forecast market assumptions;
- agreement on forecast prices for electricity and fuel;
- agreement on a cost recovery package;
- agreement between government, utilities and customers on a programme of continued regulation or of market liberalisation.

The total package for a specific company will be individual, but the overall settlement will include a common levy price to be recovered from customers within some or all sectors. The individual aspects may involve some company assets being sold to create more competition in future. They may also require a

utility to agree to accept a programme of market introduction in return for a 10-year price profile, for example.

The negotiations in the USA are clearly where the lessons are being learned, since investment was initially on the basis of long-term cost recovery through regulated prices. Market reform usually requires that these costs be recovered more quickly. In some US states, where prices were expected to rise to cover stranded costs, customers have requested that regulation should continue. This demonstrates that customers have choice here, and that a regulated solution may be the best for some markets.

3.4 To Attract Private Investment

Success in attracting private investment is demonstrated if sufficient generation projects are constructed and commissioned in time to meet demand growth. In terms of the electricity industry and market influences, the key requirement is that the investment banking community regards the market as sufficiently stable and that each investment project will be able to repay the large debt that it will have. The levels of debt will be around 70% of project cost, and this will involve the repayment of considerable amounts of interest.

The stability of the market is therefore very important, and the understanding of how the market will perform over a 10 year period is what will determine the appetite for private investment. There will thus be a difference between economies which require to improve their past record of attracting investment to meet increasing demand, and those economies where past performance has been more than sufficient to meet requirements.

The introduction of a market for the operation of generating plants will be seen as a major risk in markets that already have excess capacity, even if it is old plant, since it can be refurbished cheaply and all the connections and licences are there for rapid recovery. Other risks involve the government or state industry retaining some plants, even if they are held in reserve or mothballed, since they could be used to cap or depress market prices.

A key criterion is therefore that the government understands the requirements of the investment banking community and has responded by taking its views into account when proposing designs and timescales for market development.

Failure to attract sufficient private investment will delay market introduction, and it is important that any such delay is used to build confidence by creating past performance and track records to demonstrate the stability required. This stability must be reinforced by stability in the performance of the government and regulator in the use of their powers. Powers to mandate rapid change in market conditions usually reside with them, and foreign investors will need some comfort that such powers will be judiciously used.

Another key factor is whether or not new investment projects have an advantage over existing plants through lower costs of operation. This occurs easily when there is a new lower cost fuel. In this situation, investors are comforted that under competitive operation they can expect to achieve their target volumes of generation. Hence government-backed cross-subsidies to other plant will be considered as a threat.

In markets where new generation cannot guarantee its output, the investor will require a long-term contract that covers the risk. All of this is within the broader market environment, and if expected returns are low the investment community will look elsewhere. The overall requirement for investment worldwide is large and investors can afford to ignore markets with unmanageable risks. This is one of the main reasons why the Study Coordinator considers that an alternative approach to reducing prices, using regulation to give more certainty, should be considered in some cases, at least for an interim period. This can reduce the market costs and increase investment.

Key criteria of whether a market will be attractive to private investors are therefore:

- There is clear demand for additional capacity, for example, the government has a plan for the required private investment in the electricity industry and associated industries (e.g. fuel delivery).
- The government and industry regulator have demonstrated stable and predictable performance over two to three years.
- Powers to change market conditions are reasonable and balanced, with efficient arbitration methods for resolving disputes.
- Generation projects using new technology or an alternative fuel have significant cost advantages over existing plants.
- New plants are needed to run as baseload to meet demand.

This important area of the national investment environment is further discussed in Chapter 4. However, as a general rule it should be understood that investors do not seek competition for their investment and will prioritise markets where competition is least, provided access can be achieved. The final criterion is therefore that any competition that is forecast is seen to be small by the investor.

This will inevitably influence the strategy with which a government privatises its assets, and hence investors should have independent verification of government forecasts where possible.

3.5 To Maximise Asset Value

A government will have the objective of maximising value to some degree when it considers privatising some of the assets of the state utility. It has a responsibility to the electorate to achieve a fair value for state assets, and under conditions of high borrowings it may seek to achieve maximum value.

Certainly early privatisations of distribution companies in South America (Colombia and Brazil) achieved high asset values, and generation assets in Victoria (Australia) received significant interest. Usually five or six investment consortia were interested, and the premiums over expected values were more than 30%. Privatisation value in the UK was not maximised. Being the first in a novel market did not help, but the emphasis was on introducing competition and customer choice. In addition, the UK did not need the revenues to reduce debt in the industry.

Since the early privatisations, market performance in terms of electricity prices has been disappointing for investors in several markets. Competition in Norway, Argentina and Victoria has driven prices lower than expected and investors have not achieved the rates of return that they had hoped for. During the last three

years, assets put forward for sale in the generation sector in Brazil, the Philippines and several US states have received lower tender prices than expected. However, assets in some other US states and in New Zealand have achieved premiums. In the first group, market risk and unpredictable generation levels were the key influences leading to lack of interest from investors.

A valid strategy, therefore, for a government wishing to sell assets over a two to three year period would be to forecast prices higher than might be expected and to present as stable a position as possible on future market changes, possibly lengthening timescales and understating the degree of competition desired. Once sufficient assets are sold, the electorate's desire for the lowest possible energy prices may again carry greater weight. The strategy is therefore to encourage overpayment for the assets initially, and then to deliver lower income to them later.

There are also other tactics that can assist in this strategy. Since the government and the state utility have an advantage with information on past performance and on plant capability and costs, it is quite possible to sell a generating station with a contract to purchase power that has either too high or too low a volume.

With excess capacity in a market, a station with a contract for a load factor of 60% may seem attractive if purchasers consider that they could achieve 70%. However, unknown to the investors, in an operational cost order of merit it may realistically be expected to achieve only 50%. The outcome is that the station may be sold for a premium, but in a future pool or bidding market to achieve operation it will be encouraged to bid below its costs to achieve its contracted output. It is therefore discouraged from raising pool prices, which then fail to reach forecast levels. When generation assets are sold in separate groups it is quite easy to include inconsistent power purchase agreements that make the assets appear more valuable.

Another tactic is to retain some generation in state ownership, on the grounds of supply security, nuclear safety or environmental considerations. In competition this plant has the advantage of lower costs of borrowing. Privatised plant has to service high interest debt charges. In addition, the government-owned plant may bid to reduce energy prices in future.

The above are risks that may either be overlooked or be impossible to quantify.

Alternatively, a government can be as transparent as possible and provide all possible details on future plans for the market, or wait until the market has operated for some time to build a track record. This certainty will attract a premium because the prospects are more predictable. However, this takes time and the government must fund the development of the market before receiving the sales income.

Increased predictability can be achieved by specifying prices into the future. For stranded cost recovery this is often required for periods of up to 10 years. This enables revenues to be more certain, and profitability will be influenced by improvements in efficiency and reductions in costs.

There is a close relation between the value of an asset and the income stream. In the case of a generator or a vertically integrated utility this value is heavily dependent on the price of electricity. Therefore a government must make a decision on the balance that it wants between privatisation value and future electricity prices. It is free to determine this balance, and in particular it could

choose to determine forward energy prices through regulation. Privatisation income could then be determined through competitive tender.

In the UK, some eight years after privatisation the government imposed a “windfall tax” on the new private companies to raise further income, as it believed that the assets had achieved too low a price at privatisation.

Realistically, the only criterion relating to this objective is that the government decide its priorities regarding future energy prices and the short-term income from asset sales (and hence debt reduction). Value, debt and future prices are related. If the priority is the future of electricity prices and the conditions for competition are unsuitable to achieve the desired levels, then the government can determine prices and leave investors to value the assets as a result.

A clear observation is that the maximisation of asset value and the introduction of competitive prices are mutually inconsistent, if the full extent of competition is known to investors beforehand. The subject is further discussed in Chapter 4.

3.6 To Entrench Universal Service Obligations

Electricity industries have standards for connection and for supply. Utilities operate within these standards and are normally obliged to offer them to all customers. However, in remote areas new connections can be very expensive and supply security levels more difficult or impossible to maintain in the same way as for high demand areas supplied by main grid connections.

Under competitive conditions, remote and/or costly new connections may be neglected by private distribution/supply companies that have agreed regulatory terms. The incentive would be to reduce costs. There will be competition to connect the least cost customers, but not those with above average costs, unless these costs are allowed in the regulatory rate base.

If regulation is on a cost plus basis then such customers may be connected. However, to control costs within some range the regulator would wish these costs to be reasonable. When this is difficult to determine, it may be more sensible for a government plan to identify expenditure required to service the most costly connections, since this can not be recovered from those new customers within standard tariff rates.

The problem therefore arises irrespective of whether cost recovery under regulation is based on standard tariffs or on a cost plus basis. The latter is based on agreed investment in the future review period.

The alternative to cost-based regulation is to remove investment sectors from the competitive market if it is predicted that such investment will not materialise. The government could manage investment within a plan and such projects would be funded by a levy charged to all customers. Although it is best to minimise cross-subsidies where possible, in reality there always will be social issues and special schemes which require funding from outside the competitive sector. The important aspect is to identify these initially, so that the government is not accused of forgetting communities with the resulting poor public relations.

The criterion for this objective is a government development plan which identifies investments that are intended to be funded from central government resources, separately from other electricity industry investments.

A market test of inviting tenders for construction, ownership and operation could be adopted. This would identify how competitive private investment is and the lowest prices to be charged to the new customers. The government can then subsidise prices to the chosen tariff threshold. This is the method adopted by several governments to encourage renewable energy schemes.

3.7 To Promote Integration of the Grid

Transmission constraints can fragment a potential market and severely limit competition. However, it does not make economic sense to construct more transmission capacity regardless of cost. The economic criterion is that a new transmission line is constructed if its construction and ongoing maintenance costs are lower than the out-of-merit generation costs caused by the constraint which is removed.

These costs would be compared over the required pay-back period. If the alternative costs would both be incurred within the same company then a reasonable decision may result. However, the usual problem following restructuring is that the decision to construct lines is the responsibility of a monopoly transmission company that is regulated on an agreed cost base and hence has the incentive to spend money, whereas generators are trying to maximise profits by achieving as high a price for their energy as possible.

There is a price that the market would be willing to pay a generator to avoid the transmission investment. The generator could be contracted to produce the required output for a period of years to ensure overall cost savings. If the generator refused, then construction of the new line could take place. The threat of loss of earnings would often be sufficient to gain a reasonable price. The threat of an alternative provider is effective across the whole industry in producing reasonable prices.

A more difficult negotiation is needed when two independent grid systems with differing price levels are connected. If these both operate marginal price markets which then account for transfer flows, then the prices in one region will rise and in the other will fall following interconnection. If these price changes are passed on to customers then one side will complain. Another issue is how the savings are shared between generators and transmission line owners. This is the specific problem affecting Australia and Germany. In Germany, several schemes have been proposed but agreement between private companies inside Germany and those outside has yet to be achieved. This failure to agree results in competition being delayed, to the benefit of some companies.

Where all assets are owned by the state the solution is easier, since overall optimisation of interstate transfers can be achieved and charging principles agreed more easily. In the USA, transmission charges are based on firm and non-firm capacity rights, which typically are US\$3/MWh and US\$1/MWh. The incentive for well-connected utilities may be to encourage as much trade to flow across their lines as possible, with each trade attracting charges. However, the real flows are the net flows (difference), and are limited by stability and security standards. A utility could make more profit from transmission charges than from wholesale energy trading. This is clearly a non-efficient incentive and opportunistic charges may result.

Connection between two separate states or two independent countries creates issues of regulation of a monopoly asset. The value of such an interconnection can be determined from the difference in marginal prices or costs in the two market regions being connected.

Among the criteria is that the charges for use of the interconnection are decided beforehand, whether they are to be fixed and regulated or based on variable opportunity cost savings in the adjacent market prices. In each case there needs to be an entity that can despatch and settle payments for transfer flows. Pool agreements can leave a hole in this respect and the transmission businesses may be the beneficiaries as intermediate traders.

Once charges are agreed, the rules for despatch and the methods of bidding into the adjoining markets are required so that the project value can be determined. Rules are required to determine how the transfer energy is represented in each market, and who pays, who receives and who despatches.

The representation in each market is likely to be different. The cost information would include the price of the generation to provide the transfer plus the transfer charge. The receiving market would have the interconnection represented as a generator with this price. The two markets therefore have to be modelled together to determine the flow direction and the price of the transfer. An agent is normally required to perform this, and therefore an agreement is needed between representatives of the two markets. The despatcher should be independent. In times of shortage, utilities with despatch responsibilities tend to favour their own interests (e.g. as in US high price periods).

Other difficulties relate to the accounting for losses within a market. It would be simple to model a line of markets in which a transfer flows from one end to the other to give the impression of power being wheeled thousands of kilometres. Of course, losses and transmission charges should discourage this, so it is important to reach agreement on rules and payments to ensure these are consistent with physical reality and provide the correct economic messages to all markets. It is very easy for one market to exploit the next through inconsistent or non-reciprocal agreements. This is an issue in Western Europe where, for example, France exports into adjacent markets (the UK, Spain, Germany, Belgium, etc.) but does not yet allow equivalent entry into its own market.

Thus, countries may try to enforce some non-reciprocity in the rules governing the interconnection. However, in most markets traders from outside the region that are permitted to connect to the market usually take more benefits from that market than they give. Hence the political dimension to the issue.

3.8 To Reduce Debt

As mentioned in section 3.5, the reduction of debt is related to other issues such as future electricity prices and the value of assets being privatised. The value of generation assets is related to wholesale energy prices, and transmission and distribution assets to transmission tariffs. However, if only end tariff prices exist in an integrated industry then the individual businesses will need to be restructured before individual assets can be sold.

The ability to repay debt depends entirely on the owner, and in most cases this is the government or the state industry. However, the end-customers will eventually make the repayment, and hence the government will need to have a plan that takes

into account the ability of customers to pay and the period over which repayment will take place.

Repayment will be through the price of electricity, which may include a levy to pay for other cross-subsidies as well as debt. If most of the price of electricity is made up of these additional charges then the introduction of a market will have little effect on customers, and large expenditure to implement the market may be heavily criticised. However, electricity revenues are often a strategic income for the government and it would want them to continue if possible.

The strategy of many governments that have already privatised their electricity industry is to encourage competition to reduce income to the industry while imposing government levies on electricity to pay for other matters. The size of these levies depends on the government's view of the electorate's reaction. If these can be applied while reducing the overall price then the public reaction may be small.

A government may aim to replace almost all the price reduction that competition can achieve with such levies. This is often the key strategy for the government, rather than reducing the price of electricity to most customers. For those customers that need low energy charges in order to be competitive overseas, an option for the government is to give partial exemption from the levies.

A government can therefore decide what electricity prices are going to be in the future, and can repay debt according to this plan. The plan may include the introduction of some mechanism to force the industry to receive less income. This incentive is not there if the government is still the owner.

To optimise debt reduction, therefore, the government should have a strategic plan which includes the following steps, in chronological order:

- The sale of non-strategic industry assets, while understating the impact of possible future competition.
- The introduction of an aggressive regime for reducing electricity prices as much as possible; this may be through regulation, legislation or competition.
- The imposition of the maximum taxes/levies possible without causing adverse public reaction.

A similar strategy applies to a private company wishing to reduce debt on its balance sheet, except that it is more limited. The company must have a strategic plan which includes, in chronological order:

- The sale of non-core or non-strategic assets, while understating the impact of possible future competition.
- The introduction of an aggressive regime for reducing costs as much as possible.
- The imposition of price rises that are profit maximising and which market power will achieve without causing financial penalties from the regulator or public.

4. ISSUES WITH MOST FINANCIAL IMPACT

The following issues were selected by the Study Coordinator (section 1.5) as being those having the largest financial impact on an economy, and are presented in the order of priority which he attaches to them. Several of them were also discussed in Chapter 3, but are analysed here in greater depth because of their financial importance.

4.1 National Environment for Private Investment

The key criteria are that electricity demand is being met at all times, and that it is forecast to be met for the next 5–10 years with the current investment environment. Success in meeting demand over the previous three years will demonstrate if adequate generation construction has taken place and proceeded quickly enough to operation. However, demand forecasts for some economies may indicate that changes to the investment environment are required, even if it has been satisfactory over recent years.

Where plant commissioning has been too slow to enable demand to be met at all times this may have limited manufacturing output, with an impact on the gross national product. If this impact is significant then the rate of growth of the wealth of the economy will be reduced. If failures exist anywhere in the process, from attracting investment right through to plant commissioning, it is usually easy to determine where these are. The difficulty comes in their remedy.

A common area for failure lies in the excessive bureaucracy that exists in most state industries and planning authorities before liberalisation changes are made in the course of restructuring. Often, too many authorities have an interest in power projects, meaning that obtaining approvals can take years. Other common problems include market-specific risks perceived by foreign investors, unpredictable and inefficient application approval methods, contract management, and regulatory and legal frameworks.

The success in some markets of independent power producers (IPPs) with standardised power purchase agreements (PPAs) has led to strong competition for such projects. The result has been that governments are now trying to avoid risks themselves by increasing the risks placed on the project investors through the PPAs, and also through a lack of detail in the specification for future market design and regulatory powers. The reaction from investors, particularly the investment banks, has been to walk away from such risks, since there are investment opportunities in other markets.

It is beneficial to remove market-specific risks where possible. The standard forms for contracts for power projects, particularly those for IPPs, are familiar to investment banks and industry participants. Although the market for IPP projects has become very competitive, to deviate significantly from these familiar forms may result in the commercial risks being difficult to quantify and the competition to win the project might not materialise. There have been examples in South America and in the Asia Pacific region over recent years where only a single consortium (or occasionally none) has put forward a final bid. In each of these cases the commercial risks were difficult or impossible to quantify, because of unspecified market changes in the future or unpredictable generation output. The

fuel and power purchase contract forms, and the length of the contract period, need to be balanced against the investment appetite.

In other cases, early IPP projects used contract forms that left little risk with the plant operator for operational output. In the early 1990s, with the introduction of competitive power pools in England & Wales, Argentina and Chile for plant despatch, contract forms once again left IPPs with little risk for operational output. What is more, market changes were introduced with vast quantities of written specifications before privatisation took place and new investment was attracted. The future market environment was defined. However, as these markets have built a track record for determining the output of generation under the specific competitive conditions, some output from recent new stations has been left to take the spot market price together with the associated risk of not operating to full capability. Similar positions have arisen in Australia and New Zealand. However, these markets are relatively stable and predictable, and despatch can still be achieved by bidding low enough.

In the mid to late 1990s, and particularly following the rapid currency exchange rate changes in some Asia-Pacific countries in 1997, many governments wanted to reduce their debt by either encouraging foreign investment or through privatisations. The requirement was for rapid reductions in government spending and debt, before the future market environment had been defined. The resulting additional risk to generation output, without a market track record or even the rules of the market being defined, has turned out to be far too high for the investment community in general. However, there are still a few cash-rich power companies that will invest in the unknown, particularly those companies in highly regulated home markets (e.g. the USA), or those companies owned by governments that have alternative means of raising cash (e.g. Western Europe).

The conclusion is that an investor must be able to determine, to a reasonable probability, what the generation output and price is going to be for his project. If rates of return are in single figures this probability must be known to within a few percent. This level of confidence is impossible to assess in many of the emerging markets where sufficient detail has not been provided.

4.2 The Balance Between Government, Regulator and Industry

As mentioned with respect to the previous issue, it is becoming more common for the authorities concerned to change market conditions in a way which has not been specified in advance, or for very wide-ranging powers to be allocated to certain individuals or authorities without limitations. Again, the risks of change in revenue income cannot be adequately estimated for valuation purposes.

Over recent years, the stable positions of some governments (national and local) that had not been expected to change radically, have in fact changed significantly. This has undermined investors' confidence. Examples are:

- In the UK the electricity market and other utility sectors were very open to foreign investment under the Conservative government. The change to a Labour government in 1997 saw the introduction of a "windfall tax", effectively a tax on retrospective capital valuations under which companies that had been privatised years earlier had to pay large sums to the government. This effectively stopped inward investment from US companies and turned profitable investments into loss makers.

- In the USA, Californian regulators negotiated with the incumbent utilities the terms under which stranded costs could be recovered. As part of this, several utilities agreed to sell off their fossil generation plants and agreed increased retail tariff rates for the following 10 years to recover other costs (e.g. nuclear stranded costs). However, shortly afterwards the general public, to whom the regulators are responsible, demanded a referendum on the increases in tariffs. This referendum narrowly failed, but if it had succeeded the utilities would have made the divestments in exchange for the tariff rates, only to find that it had been for nothing. (In the event, further increases in retail tariffs were prevented, while wholesale prices soared, helping to precipitate the more general electricity crisis in California, which is further discussed in section 5.3.)
- In the Indian sub-continent, there have been changes to or even nullification of project agreements and PPAs following changes in state governments. These have occurred well into the construction phase of projects, or even after operation had started.
- In countries affected by exchange rate collapses, the pressure to renegotiate PPA price set in US dollars has been almost intolerable for governments.

The outcome is that the risk of governments changing their minds is now perceived as significant, and for countries with emerging markets and requiring inward investment this risk will be reflected in increased prices.

In terms of regulatory powers, legislation is appearing in some markets that gives wide unilateral powers to a regulator. Licensing powers and the determination of tariff rates are now being followed by the imposition of unlimited fines for behaviour judged inappropriate by the regulator. The first pooling and settlement agreement in the England & Wales market placed the power to change market conditions with the trading companies, through democratic majority voting; regulatory powers were limited to that of a veto on changes. Other markets adopting a pooling structure have increased regulatory powers and often provide the regulator with unilateral powers to change the market rules and hence set prices, without providing any comfort to investors that significant changes are unlikely.

England & Wales, the first market to introduce a pool, is shortly to be the first market to remove the pool. It will be replaced by a bilateral contracting market in which the regulator will have unilateral powers to change the rules of the balancing market and also the power to impose fines.

In England & Wales the full circle of liberalisation has almost been completed. Before liberalisation and privatisation, tariffs were effectively set by the Department of Energy, and hence government could effectively influence investment and employment issues while raising income through this route. Following liberalisation, there were 10 years in which investments and costs were determined mainly by free market forces. However, the Labour government has now passed new legislation giving wide-ranging powers to the regulator. Thus, control of the electricity industry passed from government into a “free” market, to be returned 10 years later to regulation by government, although ownership is left with the private sector.

The UK government has therefore raised capital from privatisations but retained control of the electricity and gas industries. This cycle of tight control to very little control and back to tight control is a very natural swing, and other countries such

as Brazil and the Philippines are proposing these controlling powers directly following privatisation. New Zealand has publicised its own market as being one of very light regulation, with there being in fact no regulator. However, following almost no reduction in supply prices there is now pressure to introduce more regulation.

It seems that there is a natural life-cycle of electricity markets. First is the move from regulation towards freedom, where market forces dominate. Then after periods of aggressive competition some companies will be bankrupted. In an industry of strategic national importance it is then quite likely that government subsidies and re-nationalisation will return the industry to regulation and national control. It is also understandable that many governments do not wish to lose control over a strategic industry following privatisation.

The requirement of industry and its investors is that government and regulatory powers are reasonable and stable over a suitable investment period, say 10 years into the future. Investment is easier, and therefore more forthcoming, if investors have a reasonable level of influence in the industry, and there is no bias towards certain participants in the industry.

4.3 National Investment Strategy

A key requirement for a government is to deliver a strategic energy plan which is most beneficial to the health and wealth of the economy for the foreseeable future. The future here is longer term than 10 years, probably in the range 20–30 years.

For an electricity industry in state ownership there will be an energy plan, which will be the direct responsibility of the government. The issue for the government is, can it deliver its energy plan at the same time as privatising its assets and introducing market forces?

Clearly, left to market forces new construction will be determined by lowest costs of production. Hence the lowest cost fuel source is likely to be exploited. If this is natural gas, then it is possible to replace the whole of the existing generating capacity within three to four years. If the gas is an indigenous fuel this may be beneficial. However, diversity of supply may be strategically important if fuel has to be imported.

If large investment and employment exists in industries that become uncompetitive in this new market then serious labour and stranded investment issues arise. These have to be costed and resolved, and possible alternative strategies have to be compared with that of introducing competition. Import-export implications, as well as redundancy and unemployment costs to the state, can be extremely large, certainly of similar magnitude to the costs and benefits of certain market designs. When other factors such as state or local taxation and subsidy revenues are involved in electricity prices the issues become even more complicated and costly to resolve.

For utilities already in private ownership prior to market introduction, the issue is one of optimising the return on investment in the future market environment, where some investment costs may not be recoverable. Consequently, when market details and future regulated income are both unknown, the investment strategy for the future is not so clear and the tendency will be to invest less until the future becomes more certain. New entrants, creating the competition to the existing incumbents, will tend to invest more rapidly.

4.4 Rate of Debt Reduction

Several governments are holding very large levels of debt within their electricity industries. Some are collecting lower revenues from customers than the costs of producing the electricity, thus increasing the debt. Opportunities for reducing debt are limited to the realisation of capital from privatising assets, reducing the future ongoing costs, and increasing the income from customers and from taxes on industry.

In some cases, the need to continue increasing income from customers, including households, is certain. Therefore the government might as well set future electricity prices according to a programme designed to repay the debt. If future prices to end customers are planned there is no point in investing significant expenditure in introducing markets for these customers. Any benefit in competition will be limited to reducing the costs paid for production. Both of these requirements are compatible with continued regulation.

Production costs may be controlled through cost-based regulation to determine merit order operation of generating units. Some of the South American "markets" use seasonally based costs for production pricing. This only involves an information flow to the system despatcher, with no significant investment above that normally budgeted.

4.5 Balance Between Asset Value and Future Electricity Prices

The value of state-owned assets upon privatisation can be very substantial. The value of the generation, transmission and distribution assets depends upon their revenues, which are determined by the wholesale energy prices and transmission charges.

While assets are in state ownership, the government has some responsibility for obtaining reasonably full prices for them. However, as discussed in section 3.5, plans for the government to introduce a very competitive market will reduce the valuation prices for these assets. Maximising asset value and the introduction of competitive prices are thus mutually inconsistent. Therefore, the most important requirement must be given priority.

Of course, it is possible for politicians to sell state assets while presenting an investor-friendly view of the future, including of electricity prices. Then, once the assets are sold, politicians' responsibility to the electorate may be seen as achieving the lowest possible energy prices, and the view of the future may change. The message to the private investor is "buyer beware".

The UK privatisations followed the definition of market rules and of governmental and regulatory powers. They also followed nine months of market operation to provide company prospectuses for privatisation with some track record. Privatisation sales in the generation sector attempted in Brazil in the absence of such a track record have been disappointing, both in terms of value achieved and numbers of investment consortia prepared to tender bids. Some assets only made the lowest reserve price from a single bidder. Earlier privatisations in Victoria (Australia), before the competitive risks were appreciated, exceeded the forecast values by some 30%. Here again, the market design and some track record had been demonstrated.

The recovery of stranded costs, discussed below, can serve to stabilise future electricity tariffs so that assets can be valued with more certainty. Under such circumstances investors are more likely to pay a premium over market valuation.

4.6 Solution for the Recovery of Stranded Costs

Stranded costs are those prior investments or commitments that cannot be recovered with expected future prices and revenues. The reason is that the introduction of competition will be expected to reduce prices, while previous investment decisions were based on fixed prices, possibly set through some cost-based regulatory formula to recover costs plus a contribution to profits.

If the power industry is wholly owned by the state, then the problem is somewhat artificial. It can be resolved in one of several ways, or it can be ignored. The investment and income do not need to match, but if debt is involved then the government can decide how it wishes to repay it. For example, it may be through a levy on electricity prices or through government bonds to raise cash.

The problem is a real one if it is private companies that are forecast to have costs that cannot be recovered through expected prices. Such costs may arise from investments in nuclear generation, long-term fuel costs, or transmission charges. They may also be environmental costs commonly associated with the clean-up of fossil generation.

The move to introduce a market and therefore to change the method of price setting comes from the government, and this results in negotiated agreements with the private companies. These can involve payments to the private companies, but a common feature is for the cost recovery to be spread over a period of about 10 years through a levy on prices, probably paid by all customers. This provides some certainty to the companies, but in return the government may try to restructure the industry to create more competition in generation by requiring the companies to sell some of their generation assets. Companies can raise large borrowing facilities on the basis of the cost recovery payments. Together with cash raised through generation sales, this has given some US companies very large investment capabilities to use in other markets.

The extent of the stranded costs to be recovered in this way depends upon uncertain future prices under competition. The government may make a higher estimate for future prices than the private companies, in order to reduce the amount of stranded costs. If agreement on the costs cannot be achieved then a market test is to put the assets up for sale and to examine the prices bid. This has typically occurred in US states preparing for competition. It has invariably involved utilities keeping their transmission/supply businesses and selling generation assets. Once these are sold, the difference between the investment cost and the price recovered defines the stranded cost, on which the amount to be levied on consumers can be based.

Problems have arisen in cases where the size of the stranded costs was so large that the resulting levy raised prices to consumers at the time when competition was being introduced, as in California and Spain. Adverse reactions from consumers have resulted.

4.7 Solutions for Related Social Issues

Each government will have specific social issues to resolve where the introduction of competition is expected either to cause major social changes or to prevent progress that is considered necessary. One aspect of this has already been discussed in section 3.6, and others are included below.

4.7.1 Indigenous Fuel Industries, in Particular Coal and Gas

Historically, electricity in many countries has been produced mainly from fossil fuels (particularly coal), with sometimes significant contributions from nuclear. Natural gas, either in liquefied or natural form, is the emerging major fuel source. Benefits include lower capital costs, shorter construction times, sometimes lower fuel costs, and less environmental impact. Consequently, where gas has the advantage over other fossil fuels in terms of fuel prices, other indigenous fuel industries, typically coal, can disappear within a few years.

Construction times of two to three years for combined cycle gas turbines (CCGTs) in principle mean that it could take as little time as this before industries that depend on, for example, coal-fired generation are redundant. Towns dependent on these industries will quickly lose their income and wealth, and enormous unemployment issues will result. This has happened in UK and is happening in Germany and Spain.

Existing nuclear and hydro generation are not replaced by gas, because the variable operational costs of gas-fired generation, which are largely fuel costs, are higher.

The social disaster that may be caused by competition can be relieved for a period of years by putting in place contracts for the use of coal. In the UK this was initially for four years, then for smaller contract coal volumes for another four years. After the Labour government came to power in 1997 an embargo on gas plant construction was imposed until new market rules were in place. These new rules are considered to be less biased against marginal priced fuels than the existing pool system. Otherwise, the UK would have changed from being self-sufficient in coal to being a net importer of gas by 2005. Periods of support of least 10 years are therefore to be expected in other European countries.

The cost of supporting such indigenous fuel industries and their associated communities is billions of US dollars. These costs become a large contributor towards stranded costs, and covering them will result in higher electricity prices for a long period.

4.7.2 Obligation to Supply and New Connection/Rural Electrification

Countries with high levels of interconnection to a main transmission system may have an existing responsibility on utilities to offer connection to any new customer at a fixed or zero charge. Consequently, there is some cross-subsidy built into connection charges for customers in remote locations.

Nations comprising many islands have natural difficulty in developing large interconnected transmission grids, and in many cases it is not economic to provide electrification by such means. Countries such as Indonesia and the Philippines have national plans for full electrification of remote communities. Initially this is to be provided by stand-alone generators for each such community.

In competitive market environments new suppliers are normally attracted to the centres of largest demand. Investment costs to capture load in remote areas would be high, and normally the customers could not pay the high costs of connection. Consequently the solution is a cross-subsidy through central government, or small stand-alone schemes in which competition only happens at the initial construction stage, if at all. Once in operation, the generator/supplier has a local monopoly.

Remote communities may have no way of raising the funds for connection to a main grid, since the investment must arise from increased trading wealth, which itself requires electricity and other services.

Governments must decide what their national policy is on connection to an electricity supply, and where the electricity prices would be too large for the local customers and a source of cross-subsidy is required. This may be raised from a levy on the price of electricity to other customers in the lower-cost competitive sector.

4.7.3 Unemployment Versus Automation

Unemployment may be raised significantly if the cost of automating processes is less than the cost of human labour. A 1000 MWe CCGT can be operated with around 35 staff on site. A similar coal station may have 1000 staff on site. However, through automation and out-sourcing of tasks it is possible to reduce the numbers on a coal station to around 200 staff. These processes are becoming normal practice in the UK and USA.

The issue is again market-specific and depends upon the relative labour and automation costs. Automation costs themselves depend on new technology and new computational methods. These tend to be imported and hence have standardised costs. The economic decision is to decide for how long such tasks should continue to use large numbers of staff. If this is a robust longer term solution then it should be continued.

4.8 Grid Interconnection Within the Proposed Market Area

To allow all generators to supply to any customer requires a well interconnected transmission grid with few transmission constraints. As discussed in section 3.7, there is an economic test for determining if a new transmission line should be built, it is if the costs of paying for the existing constrained generation are higher than the cost of building and operating the new line over the required pay-back period.

This test usually is not done in an unbiased manner since the transmission company is not in competition with the generator, and may be regulated on its costs. The natural incentive is then to build as much as the regulator will allow within the regulation formula.

For vertically integrated utilities these decisions may have been taken reasonably well in the past, taking account of political pressures. The result for regulated utilities is often that within their area of responsibility transmission constraints are smaller than they need to be, but connections to neighbouring utilities are poor.

Market sizes in terms of demand are usually associated with one despatch area. To date these seem to be limited to 200–300 TWh annual volumes and distances that are about 700 km. To transmit electricity 700 km may lose 10% or so of the

power, and under competitive conditions a solution other than transmission would develop. There are therefore some practical limitations as to the geographic size of a market, and to what interconnections are required within this area.

Generation fuel costs would have to differ very significantly for a long time before construction of transmission to other market areas was considered economic. However, some connections can be justified on the grounds of supply security.

Issues for large countries become:

- How many market/despatch areas should there be?
- What overall coordination is needed so that inter-market transfers are efficient?
- How are the benefits of these cross-border trades to be shared?

These are current issues for Australia and China, as well as countries separated into island groups.

4.9 Regulated or Competitive Solution for Each Industry Sector

The 1990s were dominated by the search for competitive solutions, often without much understanding of the total costs and benefits of change. Benefits can be delivered but the costs have been unexpectedly high, billions of US dollars per annum in some cases such as the UK and California. With hindsight, it is likely that most markets could have delivered the same benefits at a fraction of the costs.

Beneficiaries have been software and hardware suppliers, lawyers, economists and consultancy companies. Those that have paid have been the end customers, and those that have lost ground have been the existing incumbent utilities. In some cases, even new entrants have also lost. The consequence is the emergence of alternative solutions, essentially negotiated price profiles for future years within a regulatory framework.

The following two examples illustrate the different ways in which competitive and regulatory elements may be blended. In the first case, significant private investment is needed to meet large growth in demand. Much of this investment may be expected from private investors, who will want stability in all areas that influence the return on that investment. This will depend upon a stable forward price curve for the income and costs, and an understanding developed over time that no major changes will be introduced that upset this. The government and the industry regulator may have powers to change market conditions quickly. Legislation, taxation and litigation procedures can have significant influence on the investment environment. However, a track record of attracting private investment in this environment over a number of years clearly provides confidence.

In this situation, the primary requirement is that the investment environment is sufficiently attractive to deliver the required construction plan for new capacity, and that there is sufficient competition to ensure competitive prices for the construction projects and their output. There is no spare generation capacity that can compete to generate since it is all needed to meet demand. Therefore competition in generation is pointless and any form of competition to operate or set prices is premature. A regulated rate of return against agreed forward prices is appropriate since the generation sector is still an effective monopoly.

In the second case, as before, significant private investment is needed to meet large growth in demand. Again, much of this investment may be expected from private investors. However, the state authority that is responsible for approving the construction projects is not convinced that the prices it is being offered are low enough and decides to introduce competition to operate amongst the generators, and possibly some competitive price setting for electrical energy. Since capacity is only short at peak demand, competition at periods of lower demand is possible. However, this part loading of plant may not have been factored into the project submissions initially and may turn profitable contracts into unprofitable ones.

The risk introduced for new generation projects is thus now high and may be sufficient to turn a favourable investment environment into an unfavourable one. This defeats the initial objective of meeting the peak demand growth, a goal closely tied to increasing economic output.

In the first example the key criterion is a stable and attractive investment environment in which competition is restricted to the project construction stage and the market will be regulated until spare capacity exists. The second example illustrates a different approach to the same situation. Competition in generation is seen as the key criterion to deliver lowest energy prices through competition to operate at low demand periods. The expense of introducing competition to operate could be avoided, however, if the profile of required output throughout the year were specified in the initial construction projects. The annual demand profile is relatively slow to change even when a market is liberalised, and could be used reasonably safely for 10 years for project valuation purposes. However, the specification of less than full-load operation makes a generation project more expensive, resulting in higher contract prices.

The conclusion from these examples is that a regulated solution may be more appropriate and have lower overall costs in some situations. However, the popular theme recently has been to introduce competitive market forces wherever possible without a full understanding of the costs and benefits involved or of the appropriateness of the design to the current conditions.

The key criterion for the above examples has to be "to meet the expected demand growth". Other criteria are subsidiary, but, in the view of the Study Coordinator, "to have an attractive investment environment" should come before "to introduce competition into generation". The first of these three is a criterion since it is measurable in several ways. The latter two are really objectives, which are not measurable unless specified in more detail. These three also tend to follow in chronological order in terms of when they need addressing.

For markets that have features which clearly disadvantage competitive solutions and which would be expensive to resolve, the Study Coordinator would advise the search for a negotiated regulated solution as the way forward for the next 10 years. This is addressed specifically in the observations for the specific liberalisation plans, which are presented in Appendix 3. A problem is that politicians and company leaders often wish to make a mark in the short term through proposals for significant change, while progress is often better achieved through evolution rather than revolution.

4.10 Form of Competition in Generation

The whole electricity production chain, from fuel supply right through to electricity supply to the individual customer and the related services, should be examined for the potential for the introduction of competition to deliver benefits.

Fuel supply. An adequate diversity of fuels for supply security, and several potential suppliers of each to ensure reasonably competitive prices, are required. Some fuel suppliers are state monopolies, which usually means that prices are not closely related to costs. Generating companies should encourage competition, possibly by having access to facilities to import fuel to create competition with an incumbent monopoly.

Generation capacity construction. Sufficient competition at the tender submission stage is needed to be able to choose a resilient and reasonably priced offer. The winner may not be the lowest priced since the approving authority may identify risks. In the initial stages of tender preparation, the intention to submit bids is needed from at least six consortia, judging from experience of drop-out rates before submission. At least three bids need to be received for evaluation to give a reasonable chance of identifying a reasonable project offering. If projects are not attracting at least three competing bids, the government should understand why this is so and try to improve the situation.

Competition in generation operation/despatch. The most common form of competition for operation is by bidding into some form of pool. The frequency of bidding can be daily, or more frequently for market models representing pseudo real time conditions. However, other markets, such as in South America, use a merit order of scrutinised costs over a season, so that real time price changes are not used, although real time availability is used. It would be possible to use annual bids, which would put higher risk on the generators and encourage them to bid down to costs, since failure to bid low enough could result in no operation for a year, other than for supply security reasons.

The purpose of varying prices throughout the day is to reflect changes in costs through the day, which arise because of different generation types, but also to provide price signals to wholesale purchasers. However, if customers cannot respond to the signals there is no point in providing them. A daily or less frequent price variation could be used with simplified trading rules for the market. This is examined in greater detail, including numbers of competitors and different types of pool and market design, in Chapter 5.

Competition in transmission. Because of investment costs, it is not realistic to expect competition in grid systems. However, it is important to ensure that costs of new construction are competitive by opening up major investment to tender. Several suppliers of the required services will prevent monopoly profiteering.

Competition in distribution. It is often the case in the USA that distribution lines of different companies run down the same streets. This arises from there being many small distribution companies. Competing distribution charges could arise under these circumstances. However, it is more normal for a distribution company to have an allocated geographic region, within which it is regulated. Thus, similar considerations apply as to transmission. Nevertheless, new lines could be constructed by independent companies if prices for connection were considered too high.

Competition in supply and/or services. In the more liberalised markets, the supply of electricity is separate from the distribution function. The reason is that distribution is a natural monopoly, and services that can be opened up to competition, such as servicing, meter installation and reading, and supply have been removed from the distribution company. The role of a supplier is the purchase and sale of electricity, together with the services of customer data procurement and billing.

Supply is therefore a low margin activity, with suppliers all using similar technology. The consequence is that five or six competing suppliers are probably sufficient to provide adequate competition. As the suppliers are the purchasers of energy from the generators, in markets where there is an excess of production the suppliers will have more market power to negotiate competitive purchase contracts.

5. POSSIBLE MARKET DESIGNS

Building on the observations laid out in Chapters 3 and 4, this Chapter covers the logical options regarding the introduction of competition in areas related to generation. The main activities of interest to the Steering Committee were taken from the reports on the proposed liberalisation plans in Chapter 2. These include construction, despatch, price setting and sales.

5.1 Construction of Generating Plant

5.1.1 Option 1: Forms of Central Planning

In this option, new capacity is commissioned by the state utility or government according to a national energy plan that meets foreseeable demand growth. Sites are chosen within this plan. The utility has the following choices:

- It can manage and fund the projects.
- It can hold auction tenders for independent consortia to manage and construct projects, which are then owned and operated by the utility once commissioned.
- It can hold auction tenders for independent consortia to manage, construct, own and operate projects, with the output being bought under contract by the utility.

The utility is then delivering a state plan for generation at the sites it requires, and with the diversity of fuel and technology that it requires. Employment and environmental constraints will contribute towards the plan. If the whole central planning process is efficient then in principle it should be able to deliver lowest cost energy within the given political constraints. Problems may be produced by excessive bureaucracy, which causes inefficiency, and also because utility staff who interface with the general public tend not to be customer friendly. Hence the utility may develop a bad public relations image, which results in demands for change.

5.1.2 Option 2: Constructors' Free Choice

In this case, new capacity is built by free enterprise, with its own choice of fuel and technology, wherever it can see the market opportunity and can achieve the necessary planning and connection approval. There may or may not be constraints on how the output can be sold. It may be sold to any of the following:

- a central purchasing agency (perhaps a state utility);
- directly to customers;
- a form of pool or spot market.

Local and national policies can be reflected in planning application approval procedures, however. Hence the free enterprise is never very "free".

For such a construction project, the means of selling the output is one of the major risk areas, particularly if the project either has to contract with customers before construction begins or has to take risk in a competitive market. To date, in only a few markets has construction commenced without the project having contracted almost its full output. In the USA, where prices are expected to rise, customers are still reluctant to contract at prices higher than existing wholesale levels. In the

UK, Spain, Germany and Australia, customers expect prices to fall, and hence will also not sign long-term contracts. Either way, the absence of long-term contracts makes construction of new plant problematic.

In new electricity markets just commencing liberalisation the stability that a central purchasing agency provides is an important factor in improving the investment environment. Where the starting point of market reform was a vertically integrated, monopoly electricity supplier, the structure of a central purchasing agency exists in any case. Until such time as sufficient generating capacity exists for competition to be effective in controlling electricity prices, regulatory control is desirable in any case, so this too is compatible with a central purchasing agency. However, like any arrangement involving long-term purchasing arrangements, the sharing of risk, particularly pricing risk, is difficult and needs to be carefully crafted and negotiated. The challenge for markets like China, Taiwan and Indonesia is to arrive at an allocation of risk in the contract terms that is acceptable to them, but also sufficiently attractive to investors to ensure there is competition to construct the amount of capacity that will ultimately make competition to despatch possible.

5.1.3 Option 3: Hybrid

In this option the government and the state utility have a national energy plan and private investors are invited to tender for projects within the plan. Other projects are allowed to progress separately to achieve planning approval. However, projects within the plan, which have not found private investors, are then commissioned by the utility. Construction thus always exceeds the plan and eventually contributes towards competition. Rural electrification and other social obligations are included in the national energy plan, and are funded through subsidies if private investment is not forthcoming.

The primary requirement in construction is to encourage production costs which are as low as possible. This can be achieved by two alternatives. The first is through knowing all of the contributory costs and allowing a reasonable return on investment. This is assisted by "open book" policies, but both parties may not agree to this. If this level of cost information is not known then the usual alternative is to encourage several competitors for each project. Competition is only possible when there is both an excess of investment capital for these projects and also several investment consortia for each project. In several markets over recent years these requirements have not been achieved.

Most independent projects are financed with around 70% debt, which requires most of the income from energy sales to repay debt. Hence competition relies heavily on the relative interest rates, required rates of return, taxation and cash availability. Interest rates may be several percentage points lower for government-owned or backed consortia, and many such US and European companies have large cash resources to spend. Some of this has come from stranded costs pay-outs and from plant divestment sales to create more competition.

If a market is not attracting sufficient investor interest to receive at least three bids for the final tender stage then the investment environment needs to be made more attractive.

5.2 Generation Operation and Price Setting

The relationship between the despatching of generating units and the setting of prices varies considerably across the existing electricity markets in the world. A government should consider these two factors separately before consciously making a decision on how to relate them. Most commodity markets consist of forward contracts that become physically deliverable at some future time. Some electricity markets try to operate as real spot markets, while others separate prices from short-term physical despatch.

This separation is, of course, similar in principle to setting annual tariffs for consumers while operating the system to criteria other than true cost merit order. The reason for departing from true cost may be that other factors are included in the merit order, such as labour issues, fuel policy and supply security issues. These factors are normally involved when the industry is state-owned and before liberalisation.

Another issue is that the true cost merit order will differ according to different definitions, but should be consistent with what is intended to be achieved in the market proposals. In competitive markets, individual power stations owned by the same company will compete internally, but forward costs will depend on past investment so that, even within a company, merit orders are difficult to understand. Stations may not reveal all their costs in an attempt to rise higher in the merit order.

The purpose of short-term despatch is to meet demand at all forward times and to operate the system within standards of voltage and frequency. Hence the merit order for pure energy generation is distorted by plant operation which is needed to manage transmission constraints, to provide reserve, voltage and frequency control, and all other ancillary services. If this distortion is significant compared with simple energy costs then the impact on the energy market will be equally significant.

Two of the main influences in this respect are the generation plant types and the robustness of the transmission system in limiting constraints to acceptable levels.

Generation plant types. There are very significant differences between systems in which:

- Generation is provided mainly by one plant type. Costs will be similar and despatch times for supply security will be similar. This provides the opportunity for “ideal” competition on a “level playing field” basis (Norway, Chile, Colombia and New Zealand are all dominated by hydro, while in Australia, Victoria was dominated by brown coal before its market joined with New South Wales).
- Generation is provided by rapid response plant such as hydro generation. The security of the system standards is simple to control, at almost zero cost. In some hydro markets payments are made only for energy. These markets enable the simplest of market models to be successful (e.g. Norway).
- Generation is provided by a range of different plant types with different costs and different response times, such as hydro, nuclear, coal and gas. These do not naturally compete on costs or operational duty. Market designs that attempt to force fairness of competition tend to do so by the most complex representation of physical reality. These are very costly to develop and after implementation the failings are immediately clear, in that the full physical

reality cannot be modelled. If this is attempted the different plant types do not in any case compete on marginal prices (e.g. the UK, California and some other US markets, Spain, Argentina and Australia). Argentina is competitive for other reasons.

It is important to understand why the range of plant types was developed within one market area (e.g. diversity/security, imported fuel risk, emissions control, etc.) and to decide if such policies need to be supported in the future energy policy. If so, the manner in which these are supported will distort free market competition. If this is significant then there is little point in developing a market design that is too detailed and unrealistic. Pure competition and an energy policy of any form are incompatible.

Transmission system. If transmission constraints are very low then investment here may already have been excessive, and if constraints are too large then further investment may reduce out-of-merit generation costs. There is an economic balance to be made between the costs of removing transmission constraints and the costs of constrained generation. Having reached this balance, a single market can be operated across the system. However, if constraints are large the market is partitioned and monopoly pricing behind each constraint will create separate markets that are relatively independent.

Trying to achieve an ideal level of perfection in competition will be excessive in terms of complexity, costs and timescales. Hence there is always a range of market features within which an appropriate compromise can be negotiated in the design of the market for a particular country or area.

Generation despatch and price levels involve some fundamental parameters that affect their application within a market. The predominant parameter is the timing of when pricing and despatch decisions need to be made. It is possible to determine electricity prices far in advance, such as by contract or tariff pricing. Some IPP contracts cover as long as 25 years, and may or may not take into account variable fuel prices. Wholesale contracts with smaller industrial consumers may be for one year. Contract trading may be for quarterly or seasonal contracts (three or six months). Hence the vast majority of customers do not require price information to be defined more frequently than, say, seasonal pricing. Even this can be profiled to provide price signals.

The important question is, who needs pricing more frequently than this? If it is only the system operator and a few large industrial consumers then the answer is to provide such detail for only these.

Generation despatch uses many technical parameters that may vary with time, but the key parameter is the readiness of plant to generate. This is captured in an availability statement that includes the power level and the notice period to start or change operation. System operators want plant to operate in real time in some economic merit order to reduce the costs of meeting demand. Hence costs or prices are also key input parameters.

However, do these costs change or need to change frequently? The answer is normally "No". Costs are dependent on the price of fuel, which is often bought under long-term contracts. They are also dependent on plant efficiency, which may improve slowly with investment decisions. Consequently, under aggressive competition, where prices are close to costs, one would not expect prices to vary frequently. Price volatility in a market often causes concern to consumers and

politicians, but most volatility results from market opportunism in limited supply situations and does not reflect costs. Market signals to construct capacity must be effective somewhere in the industry, but not necessarily in a short-term or spot market price.

The next key question then is, can competition be aggressive on a longer timescale and produce prices close to costs? Of course, such markets may not be considered by every observer to be open and competitive. However, if the criterion is to deliver prices close to costs, or close to competitive prices, then the simplest method of achieving this is to know what those costs are and to allow some premium for profit within a regulated contract, which may be over a season or a year. Short-term despatch can use these known cost parameters together with short-term availability information.

The success of a long timescale for generation pricing, with only despatch requiring short-term decisions, depends upon the transparency of costs, in that they are either known or delivered through competition. The two alternatives are to regulate contracts or to produce them through competitive auction. The risk for generators in longer term (over three months) contracts is that if they are unsuccessful in winning a contract they may not generate during the period of the contract, unless for emergency or reserve requirements. This would present a high risk to their viability, as it will force bids towards costs.

Since competition is only successful when there is excess capacity, one observation has to be that some generation must become insolvent. Daily bids for despatch provide generators with the hope of achieving their forecast production output. If they do not generate today, they may do so tomorrow by reducing their prices.

Another major influence on the effectiveness of short-term pricing (e.g. daily or intra-day) is whether or not consumers can respond to price variations on these timescales. If they cannot then there is no point in exposing buyers to them. In general, even in well-developed systems such as the UK, the USA and Australia the level of demand that reacts to price variation within a day is very small, around 5% on a few days each year. Wholesale purchasers are therefore providing the service of purchasing at a volatile price and selling to customers at a fixed price, just like an insurer. For this unnecessary service they will charge a premium, which increases prices to customers.

For the relatively few customers that can respond to fluctuating prices, alternative methods such as individual contracts are possible to avoid modelling the whole market on its physical operation. With longer term pricing the task of the wholesale purchaser is simplified and less risky, and therefore there should not be a significant premium for price fluctuations.

Some system operators are responsible for despatching plants under an "economic purchase obligation". This exists in the UK transmission licence, and other markets that have adopted the basics of the UK grid code and similar licences will have similar obligations. The obligation is consistent with the update frequency specified in the grid code for all plant and price data.

The options for generation despatch and price setting can be summarised as follows:

Generation despatch

– Technical parameters

– Plant availability

Cost data**Update frequency**

Fixed annually)

Fixed seasonally) + Real time updates

Fixed monthly)

Real time changes

Fixed annually

Fixed seasonally

Fixed monthly

Fixed daily

Twice-daily

Hourly/half-hourly

From the above options, a reasonable combination is underlined. For regions that have reasonably constant temperatures throughout the year, so that condenser temperatures are stable, the technical parameters will vary little through the year apart from when plant is damaged. For regions with seasonal weather variations (e.g. in temperature and rainfall), plant parameters may vary by a few percent from season to season. Hence seasonal updates would be more accurate in such cases.

For each plant, there is always a declaration of its current availability. This is updated for power level only when there are changes due to plant conditions. For reliable plant the declaration of availability would normally be the full load rating.

Cost data varies very infrequently, unless the market has a significant capacity of plant burning fuel bought on the spot market (e.g. natural gas). Even then it would not vary significantly within a day. For most markets that are considered in this study, costs are long term since they are related to contracts. The lack of competition in most of these markets means that stations will not suddenly be required to change their manning levels for weekends. (In the UK, for example, some oil-fired stations have no staff at weekends since they do not normally run. However, if prices published the day before are high and demand is high, then a company may ask staff to work over the weekend just in case the station operates. Otherwise it would declare zero availability and staff would stay at home.)

A suitable set of update requirements would be written into the grid code. The system operator would perform its economic purchase obligation by despatching generators according to the grid code.

Generation price setting is usually considered to be an activity of generating units or companies bidding into a central agency or a pool, which will be paid for their operation according to prices that are calculated from these bids. If plant is already under contract then this is a parallel income for the same duty. To avoid double payment, either the contract must reference the central market price and return one payment, or bidding to the central agency must be optional. However, the frequency of bidding directly influences the amount of data that the market operator has to analyse each day, week, month, season or year. The provision of ancillary services is often contracted for annually, mainly because the total revenues are only around 5% of energy revenues.

The question to be asked is, why should energy prices vary frequently in the market? In most circumstances the recommendation would be that price setting should be infrequent, perhaps seasonal. It has already been suggested that competitive prices could still be achieved.

The challenge for each government considering the introduction of a wholesale market is to design one which uses a default of seasonal cost or bid price information. Only when this fails to meet key criteria should a more complex market, using shorter timescales, be considered.

By this reasoning the market will be as simple as possible, and if the bid frequency can be monthly or less then much simpler data handling methods and existing total consumption meters can be used. In some markets longer timescales were used initially to educate the industry. However, this has commonly been a learning stage before a really complex market was introduced, because confidence was not high that all the systems would work initially.

There are famous examples where complicated software and large databases have failed and been abandoned. For example, in the UK a new optimiser for scheduling plant and possibly contracts was abandoned six months before market opening because it did not perform. The existing scheduler was used for eight years before another could be produced specifically to meet UK scheduling and despatch requirements.

The new electronic trading and settlement software for the London Stock Exchange was abandoned after about three years of development. The database and transaction requirements for this were smaller than those needed for the fully liberalised domestic market for electricity in 1998. Clearly, this did little to give confidence at that time in the software and systems that were being developed for the industry. The 1994 liberalisation of the market to all customers using over 100 kW (55 000 with half-hourly meters) resulted in many meter data errors entering the database, which were being corrected for the following 18 months. The result was that bills had to be estimated and some customers refused to pay, with suppliers left with the debts.

It is expected that similar serious problems have had to be overcome in other markets, but these sort of issues are rarely publicised.

The lesson from most markets is "keep it simple". Try to avoid complex new systems that may not deliver the benefits sought, and that once in place may be expensive to maintain and to develop to meet future needs. Simple systems may be discarded without much pain, but they should be replaced with other simple systems.

The table below shows the form of the generation markets used in several markets. An interesting fact is that only Argentina, Scandinavia (Norway and Sweden within NordPool) and (recently) the UK have large numbers of generating companies. All the others are dominated by one to three companies. Victoria is now within the Australian electricity market, which is dominated by the two largest New South Wales generators. Previously Victoria had five single station companies all burning lignite and the market was very competitive, which is why it is included in the table as an example of competitive conditions.

Essentially the table shows that there are now two basic models in use. One uses a pool in its maximum sense, usually mandatory, while the other uses a pool only to correct imbalances between demand and contracts previously agreed.

Market	Generation	Owner	Grid well connected?	Market model	Market price	Market timing
Alberta	Thermal	Mixed	Yes	Mandatory pool + merit order despatch	Marginal	
Argentina	45% hydro	Mixed	No	Optional pool + merit order despatch	Marginal capped	1 hour
Australia	Thermal	Mixed	No	Mandatory pool + merit order despatch	Marginal	½ hour
Victoria	Thermal	Private	Yes	Mandatory pool + merit order despatch	Marginal	½ hour
California	Thermal	Private	Yes	Contract despatch + optional balancing pool	Marginal	1 hour
Chile	60% hydro	Private	No	Cost tariffs + mandatory contracts + optional pool	Marginal	
Colombia	70% hydro	Mixed	No	Mandatory pool + merit order despatch	Marginal	1 hour
England & Wales	Thermal	Private	Yes	Mandatory pool + merit order despatch	Marginal	½ hour
New York	Thermal	Private	Yes	Contracts despatch + optional balancing pool	Marginal	1 hour
New Zealand	Thermal	2/3 govt	No	Contracts despatch + optional pool	Marginal	½ hour
Norway	98% hydro	Mixed	Yes	Contracts despatch + optional balancing pool	Marginal	1 hour
PJM	Thermal	Private	Yes	Contracts despatch + optional balancing pool	Marginal	1 hour
Spain	Thermal	Private	Yes	Contracts despatch + optional balancing pool	Marginal	1 hour
Sweden	50% hydro 50% nuclear	Mixed	Yes	Contracts despatch + optional balancing pool	Marginal	1 hour

The mandatory pool was developed in the UK to capture all metered electricity flows onto and off the high voltage grid system. Before market introduction the UK generators did not trade electricity with customers using physical contracts. Instead they used standard tariffs to charge for metered consumption. Hence the market started with a "clean sheet".

Both Chile and Norway had liberalised their industries to some extent much earlier than the 1990s. In Norway in particular, electricity was sold using physical supply contracts. Throughout Scandinavia 80% of electricity is still sold using physical contracts. Consequently, Norway introduced a market with long-term contracts (e.g. 10 years) between its vertically integrated utilities and its major customers (e.g. municipalities).

Scandinavia still has large state-owned companies that dominate the supply of electricity, and distribution charges can be large. However, marginal electricity requirements are traded on the NordPool, which now operates a liquid power exchange. The power exchange was developed by the Swedish company OM, which owns the Stockholm Stock Exchange. It developed the trading system from its financial derivatives markets. This company operates the NordPool exchange, the California power exchange, and the Alberta gas market. It has also just opened the first power exchange in the UK in preparation for the move from a mandatory pool model to contracts despatch with an optional and minimal balancing market.

The 1990s therefore saw the development of two models. The first was developed in the UK, and most of the markets introduced up to 1996 followed this model

closely. The second model dominated the last three or four years of the 1990s, and there are good reasons for this.

The first reason is that it became clear that a mandatory pool using system marginal pricing did not produce competition quickly because new entrant capacity joined the market. The UK has seen more new entrants with low cost CCGT plants than anywhere else in the world. However, in markets that are dominated by two, three or four marginal generators it may take 10 years or more before the new entrants affect the price setting capability of these generators. In markets dominated by thermal generation with a range of plant types, generators do not compete over the whole range of the price curve. At any particular demand level there may be only two or three competitors. This is the disadvantage of the marginal price system, yet all markets use this principle. The advantage is that it encourages more new entrants, but the disadvantage is that it delays competition.

Until the market in Victoria was created, with fairly unique features, the pool model had not delivered aggressive competition. The key feature of the Victoria market was five single station generators of the same type, which were sold with different contract volumes that prevented all of them having the same incentive to raise pool prices.

Apart from Argentina, the other pool markets were usually dominated by two large generating companies. US states are all dominated by one or two large utilities. After 1997, the Scandinavian model was starting to show increased liquidity. Hence the Californian model was developed from the NordPool system, but with more options and more complexity.

A feature of US states is that electricity was already delivered under long-term physical contracts, and hence the wholesale market had to start with the imbalance trades. A positive factor is that US regulations regard wholesale trading as income outside the scope of cost-based regulation, although wheeling tariffs have to be approved by the regulators. Hence the US industry supports pure trading to increase income revenues, almost regardless of whether or not it is profitable. There is therefore considerable support in the USA for using power exchanges to contribute to competition. However, the desire of all traders is to see volatility in the price. The mean level of the price is of little interest to a trader. Hence there are conflicts between customers' requirements and the interests of some of the major trading companies.

Governments should therefore consider the model typified by a contracts market in which despatch is determined by contracts, and a lower volume market is used to pay for imbalances between demand and contract volumes. The table shows that these imbalance markets typically produce prices hourly to settle these trades, whereas the contracts themselves are clearly longer term (years in most cases).

There seems no reason why an imbalance market could not work over longer time intervals, and also use costs that do not change frequently instead of bid prices (e.g. Chile), or prices capped at costs (as in Argentina). The imbalance trades could be accumulated over a month or so for settlement, and the imbalance price could be averaged monthly. Costs could be scrutinised by an independent body, as in the case of Argentina. Imbalance volumes would be known from existing metering, and if prices did not vary through the day there would not be the incentive to read these frequently and data handling would be minimised.

An imbalance market that is operated by a national transmission company could also have a single purchasing agency, where the transmission company buys and sells the imbalances. After the liberalisation of the 1990s, the re-emergence of stronger regulation is a possibility, particularly if some of the new markets produce volatile prices that politicians can use as a reason to reintroduce regulatory powers. This is the Study Coordinator's prediction for the next 10 years.

In such a case the state transmission company would remain under government or regulatory control and would operate the balancing market under its licence obligations. The UK is in the process of making such changes. It has been the only market during the 1990s to have a regulator with no powers to change the market. This was welcomed by investors in generation. Market change required new primary legislation to reverse this position, which was approved during 2000. It will be interesting to see the next move in New Zealand, where there is no regulator.

5.3 Conclusions Regarding Specific Markets

Argentina is one of the most competitive markets in the world. This is because of the large number of single station companies whose bid prices are capped by regulated costs. Profit levels are low, which is encouraging mergers and vertical integration to improve profits through further cost savings.

Australia is now dominated by two New South Wales generators that between them can raise or lower prices in the national electricity market. The generation structure in NSW is therefore the problem, together with the central role in determining inter-state transfers. There are problems with the proposed interconnections between states involving their operation and the allocation of savings. Victoria, however is an example of how competition between five similar single station companies all burning lignite, and a large state-owned hydro scheme, can work to produce continual downward pressure on pool prices, which were well below those forecast. Since joining the national electricity market, prices in Victoria have risen slightly, as marginal prices are no longer determined by its own plant, but by the NSW generators.

California was the first US state to "de-regulate" its industry with the introduction of a contracts and balancing market in 1996. Initial designs for the market were complex, just as England & Wales had been until shortly before the market opened. Both designs were initially ideological designs which were too complex to be practical. In California, additional complexity included most trading activities being optional.

Fundamental differences between England & Wales and California at market opening were:

- England & Wales had 27% excess capacity, California had significantly less and much of it was old.
- Annual demand growth in England & Wales was 2-3 %, in California it was nearer 8%.
- England & Wales had cheap new entry prices (based on gas), in California new entry prices were marginal.
- England & Wales had an easy new connection application process, California did not.

Against the competition in generation checklist in section 3.1, California would be predicted as having some serious obstacles to competition in a half-hour bidding market.

Being the first state to de-regulate and because the utilities were politically powerful, the stranded assets negotiated were high. In return for setting higher tariffs to recover these costs the state regulators required the main utilities to sell off much of their generation in the hope of creating more competition. The Californian public complained of prices being increased when competition was supposedly being introduced. The result was that a public referendum was held to try to overturn the price increases, despite the utilities having already sold much of their generation. Fortunately for utilities and regulators, the referendum narrowly failed to achieve the required majority.

To prevent the three large independently owned utilities from stifling competition, they were not allowed to make long-term purchase contracts with the generators. With sale prices fixed by regulation, the utilities could not hedge their purchase costs by law. The ability to hedge trading risk is a fundamental commercial requirement. One of the problems in immature markets is that sometimes counterparties for long contracts cannot be attracted. Many states in the US are becoming short of capacity principally because the new entrant prices are higher than the wholesale clearing price. Such is the case for new entrant gas-fired generation against coal-fired generation in many US states. The consequence is that existing generators will not sell long term because they expect prices to rise. Similarly customers will not contract at higher prices than existing wholesale prices to fund new plant construction.

California has additional problems that obstruct new construction. Environmental laws are severe and also planning permission is difficult with the public preferring to have plant constructed elsewhere. In addition, the major population and business centres suffer from transmission constraints. The location of the trading hubs on the Californian border enables neighbouring states to export cheaper power into California from the north and east. The exports from these states are not regulated to ensure sufficient supply and hence generators commercial incentives are to keep California short of supply to maintain prices high.

As the high-tech industries and Silicon valley prospered, so strong demand growth continued, yet no new plant was commissioned in the 1990s. The result during 2000 has been wholesale generation prices in the summer peaking over US\$150/MWh and over US\$300/MWh over the winter. The utilities have been forced to buy out of the new market at prices above the regulated retail prices that they can charge. Southern California Edison and Pacific Gas and Electric have accumulated debt of over US\$12 billion and the latter has now filed for bankruptcy. Purchases have not been fully paid for, which is now encouraging generators, particularly those out of state, to reduce generation for fear of not being paid.

Rolling black-outs have occurred since December 2000. Heavy industry, particularly smelters of aluminium, copper and zinc, have laid off staff because of high electricity prices and instead have traded their now surplus electricity contracts for profit. The state government has seriously considered re-regulating the industry though a first repair measure is to hold an auction for long-term supply contracts up to 10 years duration. A 10% tariff increase was allowed by the

regulators, though Southern California Edison and Pacific Gas and Electric said that 30% rises were needed for them to survive.

Some industry consumers are exposed to wholesale prices, but most have been protected by price caps, which in turn provide no incentive to reduce peak demand usage. Consequently, despite capacity shortages there has been no effective incentive to control demand and serious disincentives to construct new plant. Controlling demand would depress economic activity. The public and environmental lobbies must be persuaded to permit planning and construction if this is to be avoided and reliable supply restored.

The price rises have been transmitted into neighbouring states through trading and other utilities are showing debts of several hundred million dollars. Around 12 other states are reconsidering and delaying their de-regulations, waiting to see how the problem in California is solved, with shortages in the coming summer forecast to be even more severe.

Chile has low market prices predominantly because it is dominated by hydro generation and a few large companies that "manage" the market. Profit levels for new entrants are low.

Colombia is dominated by hydro and abundant supplies of low cost gas, both of which produce low priced electricity. Most market models would appear to operate well in this environment.

England & Wales have the most open access market in the world. However, confidence in a pool with a system marginal price and a capacity element has been undermined by the structure of the generation sector. It has become clear that two or three large generators will hold pool prices up, and the most rapid influx of new entrants has little impact for about 10 years. This is good for the new entrants, but not for the customer. New generators with high levels of debt also need to raise the pool price. In addition, the capacity element can be increased by a single company by reducing availability within its portfolio, particularly when there are plant outages elsewhere. The result has been a loss of confidence in this market design and an understanding that a large number of generators (maybe more than 10) is needed to create competition that reduces system marginal prices.

Another area for criticism has been over the RPI-x formula for price regulation (the retail price index less a percentage (x) set by the regulator) which applies to sectors other than generation. Costs in the generation sector, subjected to competition, were reduced rapidly, although prices were held high to maximise profits. Similar cost reductions were not achieved in the regulated sectors because x was set in single figures. Realistically x would have needed to be near 25% initially to resemble performance in the generation sector. Therefore distribution charges and retail prices did not see any significant reduction for five or six years, when x approached this figure for both transmission and distribution. It is perhaps unexpected that a monopoly transmission business could achieve 30% profits while regulated.

The most significant event has been the decision to replace the pool with contracts and a balancing market. Hence England & Wales will be the first market to "re-liberalise" with a new market and new unilateral powers for the regulator.

New Zealand opened the first (and only) market without a regulator. Generation was restructured into only a few companies (initially two, now four), and the nodal pricing was seen as too complicated to encourage trading. With generation

being dominated by hydro and geothermal, prices were relatively low anyway. However, price reductions to customers did not materialise. Distribution and supply companies have managed to improve profits for shareholders and there is now debate on new regulatory requirements.

New York has very similar circumstances to those of California and is becoming exceedingly nervous over its own de-regulation. The proposed market structure is very similar to that of California.

Norway started with almost all electricity sold by long-term contracts and this is still the case. However, some means of trading contracts and managing short-term requirements was required. A power exchange was introduced and the NordPool market trades forward, daily and spot markets on the exchange. The electricity system is the simplest in the world to manage since it is almost 100% hydro and it always has the lowest prices in Europe. There are no stability, reserve or ancillary service issues or costs since system decisions are "to turn the tap on or off". The establishment of the market was timely, because liquidity in trading was improving at the same time that the England & Wales pool was receiving intense criticism. Hence for most new markets the present proposals are to follow the contracts and power exchange model for the main market and a balancing pool for contract variances.

Pennsylvania, New Jersey and Maryland (USA) started a market for trading wholesale marginal energy across its member utilities' transmission regions by agreeing firm and non-firm transmission charges. Historically electricity was sold by the utilities to wholesale purchasers on long-term contracts. However, trading and wheeling became a profitable source of unregulated income, and this activity escalated significantly in the late 1990s. Contracts are despatched and differences from the contract levels at the day-ahead stage are charged at the wholesale marginal spot price. In the US Midwest, where similar arrangements operate, issues have arisen about high summer prices (US\$7500/MWh) when generation is short. Similarly, energy flows in opposite directions which cancel out are still charged for transmission, so that there is significant profit for a utility in permitting wheeling across its transmission system, providing this is not taking its customers. In north-eastern USA, new entrant electricity prices from gas are higher than current prices, and so future price rises are expected.

Pennsylvania opened its market in 1999. Key differences from California were that Pennsylvania had adequate excess capacity and its regulators set high rate levels to encourage new entrants into the market. The result is that half a million customers have switched suppliers, unlike California.

Pennsylvania regulators did not impose price caps as in California and allowed long-term contracting for utilities to hedge trading risk. For states short of capacity it is important for customers to be exposed to an incentive to reduce peak demand. This is removed if prices are capped.

Spain has introduced a contracting and balancing market. It has two large generating companies, that are vertically integrated, plus two smaller utilities, and has agreed stranded cost recovery terms with its initial four generating companies to be paid over 10 years. These terms are relative to the pool balancing price, which has produced prices precisely on target. This suggests that the market is well-managed between the incumbent utilities. New entrant generators find it difficult to find sites and customers with which to contract. Like other mainland European countries, access is the problem.

Sweden was dominated by long-term contract energy sales and, with 50% hydro and 50% nuclear, short-term variable costs are very low. It joined NordPool, to be followed by Finland and Denmark, which both have significant fossil generation. The interconnections provide mutual benefits: supply to the hydro countries in times of water shortages, and lower costs to the fossil countries. The NordPool was a relatively low cost development, but that in Finland was much lower still.

Like Norway, distribution in the other Scandinavian countries is dominated by a few large companies, but with many small ones.

5.4 Essential Features of a Market Model

The main principle of any market model is that generators are paid for generating electricity. Their income is volume \times price, so that the two features of major importance are:

- How is plant despatched?
- What price is paid for the output?

5.4.1 Despatch Rules

These do not vary significantly in form. There is an order for plant despatch which normally follows two priorities: first, system safety and security; and second, costs (with lowest cost despatched first).

Whether a plant's output is contracted may or may not be accounted for in despatch. A contract may be for the output of a specific station or it may be with a company to provide a certain volume from its portfolio of plants. Plants contracted to a host utility would normally be despatched according to their contracted output prices. However, some of the earlier IPP contracts required payment whether the station generated or not. In such cases the avoidable cost is zero and the plant would be despatched first, possibly before any other plant with declared zero variable cost.

Contracts with companies rather than with specific plants may be ignored in some markets (e.g. Chile), but the current favoured position is to allow the company to self-despatch to that level of output. In a pool, the company could afford to bid zero price if its income was provided through contracts. The requirement is therefore to ensure the plant operates, which is achieved by bidding zero price. The despatch first, self-despatch or zero price bid into a pool methods all achieve highest priority in merit order despatch. The effect in despatching contracts first, or having a contract and being able to bid zero price into the merit order, is therefore the same.

The priority order for despatch is therefore modified slightly to be:

- First, system safety and security.
- Second, contracted and zero priced.
- Third, lowest cost.

Therefore the despatch rules within a contracts market and within a pool are essentially the same. The key difference is when and how the competition occurs to create the merit order.

It is not easy to keep a plant contracted with renewed daily contracts. Hence generators want longer term contracts of a year or more to manage their annual cost risk of not running. If contracted plants (or volume) are placed before non-

contracted plants, regardless of whether they bid zero price or not, there is an added incentive on the generators to obtain contracts for their plants. If a plant fails to win a contract then the company may make a decision to close it to reduce costs, if there is little prospect of it operating that year.

Contracts then become more important since the risks are higher. The competition will be more aggressive and prices will be closer to costs than where plants bid daily into a pool.

5.4.2 Payment Price

The main choice for setting payment prices in most electricity markets is between contract price and pool system marginal price. If new entrant prices are higher than existing prices, a capacity payment element could be included in both of these choices to provide an incentive for the timely commissioning of new capacity.

Contract pricing will lead to competition being dominated by baseload prices, and customers will not appreciate the effect that their load shape has on costs. Contract trading often only has a baseload shape and a daytime shape for forward trading. A customer wants to buy electricity at the lowest price of any generator, probably hydro or nuclear, and definitely not oil or diesel. So there will be most competition for base prices and customers will complain if they are not offered these for a whole year.

System marginal pricing has been used in all markets in some form. Within pools it has been demonstrated that smaller numbers of competitors, even as many as seven or eight, particularly in thermal generation systems, are able to maintain prices well above costs for a long time. The fact that prices remain high encourages large numbers of new entrants in a free access market, especially when there is a low cost fuel such as gas available. The proposals covered in this study do not include sufficient competing generators for a system marginal priced pool to deliver lowest competitive prices, if this is the major criteria. The proposals for the Republic of Korea include such a pool and have the best chance of success.

However, there may be “better” options, and no country or area has included a contracts despatch model in their proposed liberalisation programme, similar to the NordPool or the New Zealand market. But the conclusion that many other governments and regulators have come to is that lower prices result from the more liquid contracts markets.

5.5 Market Models for Consideration

Apart from the examples which have contracts as the main source of electricity delivery (which have long time periods), the time periods associated with the examples below have been removed to encourage the designer to think how long they should be.

Another consideration is how the market can be extended to more participants in the future without a complete change at each stage of development.

5.5.1 Pool with System Marginal Price

In this model, generators and some or all wholesale suppliers bid into the pool.

This model was the first to be widely used, with a variety of modifications. These range from no suppliers included to all included, depending upon the readiness of suppliers to participate positively. Some supply customers can bid demand reduction at a price, i.e. they can bid to increase or decrease demand.

The price for all generators to sell is the system marginal price (SMP). This may or may not be increased with an uplift element to pay contributions for ancillary services and transmission constraints. A capacity element is added to SMP in the UK and Argentina, but not in Australia and New Zealand.

The pool may be mandatory or optional but the complexity of data requirements may be similar. Despatch is normally through the merit order of generator bids for mandatory pools, but contracted plant may self-despatch in an optional pool.

5.5.2 Pool with Pay-as-Bid Price

This pricing was considered in the UK and is a fundamental feature of most “outcry” commodity markets. Generators are paid what they bid. This encourages all generators to compete to set prices through the price curve.

This model is not used, but has variations that should be considered. The demand side could bid for supply in a similar way and pay the bid. Alternatively the market price could be determined as the average of the bids by generators. This avoids the problem of system marginal pricing pools where all generators are paid the same and the cost to customers is much more.

5.5.3 Contracts with Despatch Priority and System Balancing

Forms of this model, based on the NordPool, become popular in the late 1990s for new markets in the USA (California, Pennsylvania, New Jersey, Maryland, New York), Spain and now in the UK. The feature that causes competition to be more aggressive than in mandatory pools is the requirement to win a physical contract in order to be despatched. Supply contracts tend to be similar, whether from baseload plants or from marginal plants. Large customers who contract tend to be more baseload. Consequently, excess capacity in marginal plants will have to offer contract prices that compete with the lower priced baseload generation. In addition, contracts provide the right of despatch for a long time period, which encourages generators to offer cost-plus prices. For these reasons a contracts market tends to have lower prices than a daily pool market.

Despatch. The main feature is that plant is despatched with priority for contracted output instead of priority for a merit order of costs or bid prices. This priority exists in several countries, such as New Zealand. However, in Chile contracts are mandatory, with the pool serving only for generators to optimise their costs of meeting the contracts. This optimisation requires despatch to be in merit order of actual marginal costs. This is also the case in Argentina, where costs are regulated, and in Peru.

Balancing. The form of the balancing market varies considerably. It can be described as an optional pool or as a balancing market. The purpose is to allow bulk flows of electricity under contract to be removed from the balancing market and only to trade the differences from these contractual volumes. In some models only the difference is input, but in other models the total contract volumes are notified and differences determined from these. This is then analogous to a

mandatory pool but with effective self-despatch of contracted plant. In a pool with merit order despatch, self-despatch is achieved by bidding a zero price.

The prices at which balancing flows are traded vary significantly and this is one of the main areas where complexity can be avoided. In principle, the mechanism can be a complex pool, a power exchange, or a pricing and settlement algorithm; alternatively, prices may be regulated short-run marginal costs, or they could be fixed for a period chosen by the regulator.

5.5.4 Minimalist Model

The above models have all involved some central development of a complex software and settlement system. It is worth considering if this can be avoided.

Germany has nine large privately owned utilities, which did not want market reform. However, the European Union (EU) Directive on Third Party Access committed member states to allow certain customers to be supplied other than by the local monopoly distribution business. The German government became frustrated by the utilities' failure to agreeing a common approach with which the government could agree. So it introduced primary legislation obliging the utilities to allow competition for all customers. This required transmission charges, which previously had not been separated from the bundled price, to be determined. (Arguments on the method of charging for transmission still continue within the EU.) In Germany, no central systems were developed, though several independent power exchanges are being developed to operate for commercial profit.

The results of this approach were dramatic, in that 25–30% reductions in prices were offered to all customer groups, but less than 2% of customers had to switch suppliers to achieve this. The reason was that there is large excess capacity within Germany, and also outside it, for example in France. Large capacity transmission lines connecting it with adjacent countries permit about 50% of German demand to be met from imports. In addition, although there are nine large utilities, the size of the largest is smaller than the excess capacity, so that no single utility could defend its own customer base against competition, and all were in danger of losing customers due to long-term fuel commitments which were in place. This would have threatened insolvency in some cases. The result was therefore an understanding among utilities that competition for them could be a disaster and they all offered their own customers low prices to avoid losing them. Competition from other service sectors (gas, water, telecommunications) emerged immediately, though gaining new customers is now hard work.

This example is important as many of the conditions for successful competition occur in Germany:

- Excess capacity and the number of competitors were adequate.
- The size of the largest utility/generator is less than the excess capacity.
- The market is well-connected with transmission lines (cost-plus regulation usually ensures this within a utility region).

There is also a warning here about the potential impact of supply from outside a country, in Germany's case especially from France – the terms of reciprocal or non-reciprocal interconnector trading need to be clearly understood.

At this stage it is not obvious that countries and areas represented in the Steering Committee could reproduce the impact that occurred in Germany. However, some of the circumstances will be familiar (e.g. in Australia, with NSW and

interconnections), but the key is the number of competitors created in any restructuring.

The important message is not necessary for all market arrangements to be developed centrally. Some aspects can be specified in simple terms or can be left to develop naturally.

5.5.5 Simple Central Market

The following could be a base case using existing generation and total consumption metering for large customers. The market could be operated by the system operator, who would preferably be independent. Input costs and contract terms would be verified by the regulator.

Despatch priority:	1. Safety and security reasons. 2. Minimise payments and penalties in PPAs. 3. Plant/volume contracted with customers. 4. Non-contracted plant in merit order of: - regulated seasonal marginal costs; - demand reduction prices.
Generator payments:	Contracted terms; or seasonal marginal costs for volumes in excess of contracted volume.
Settlement:	Monthly or quarterly.
Suppliers pay:	Contracted terms; or monthly averaged cost, including any ancillary services uplift.

5.6 Design Selection

Which of the above approaches to market design policymakers should select will depend on the circumstances of the market into which reform is to be introduced and the key objectives which it is intended to deliver. The introduction of competition into electricity markets has brought many benefits, but the costs have often proved far higher than budgeted for. No country can afford such waste, least of all developing countries. The material in this report is intended to help Asia Pacific policymakers evaluate the benefits and drawbacks of particular design features and the outcomes that can be expected from a given design in a specific situation.

The broad conclusions are that: cost benefit analysis must be rigorous; all steps in the electricity production chain must be analysed with respect to the feasibility and effectiveness of introducing competition; the simplest approach that will achieve the objectives to a reasonable degree should be chosen; and blending market and regulated features will often help simplify design, particularly in new electricity markets.

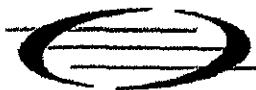
APPENDIX 1. QUESTIONNAIRE

This Appendix reproduces the questionnaire which was developed to collect information about the costs and benefits of liberalisation changes introduced in various electricity markets.

The questionnaire was necessarily long and attempts to extract information on the benefits delivered by reforms, as well as any disadvantages, together with the resources, finance and timescales involved. The questionnaire was designed in sections to allow further distribution, so recipients did not have to respond to all sections, only to those covering their area of expertise. Thus it could be divided among experts to be less onerous on any individual.

However, in general it can be expected that there will be experts within a market that have direct knowledge of at least 80% of the information required without reference elsewhere. The challenge is to identify those individuals. If the questionnaire reaches these experts, the time required for response can be short (four to six weeks).

The letter covering the questionnaire (also reproduced below) explained the above, asking only for the respondent's personal experience and knowledge without requiring answers to every question. It was explained that gaps in their answers might be filled by other contributors with knowledge of the same electricity market. To encourage responses the task was made as simple as possible. It was found that with such an approach, for each market covered it is probably necessary to get replies from around five recipients with different roles in the market.



World Energy Council

CONSEIL MONDIAL DE L'ENERGIE

To promote the sustainable supply and use of energy for the greatest benefit of all

5th floor, Regency House, 1-4 Warwick Street, London W1R 6LE, UK

Tel. (+44 20) 7734 5996 Fax: (+44 20) 7734 5926 E-mail: info@worldenergy.org Website: www.worldenergy.org

Dear Electricity Executive

ELECTRICITY MARKET QUESTIONNAIRE

The World Energy Council needs your help so that we can help others. You are an expert with knowledge of various areas of the electricity industry in your state and country. Your knowledge and experience can help others to develop their own electricity industry to meet the needs of their country.

The purpose of this questionnaire is to capture Electricity Market Experience from around the world focussing on practical and cost-beneficial features of the markets to feed into a study being undertaken by the World Energy Council. The World Energy Council is a non-profit organisation and it is hoped that participants will be sufficiently generous with their input of specific experiences to create a library of high quality information.

Information will be collected over the relatively short period of 4 to 6 weeks. It is hoped that recipients of the questionnaire can reply by **31 October** to enable a report co-ordinating the information to be produced by the end of December 1999.

The information will be made available to those who are in the process of creating an electricity market or are in the process of transition or review of their market. It is hoped that access to this knowledge will be beneficial for those market creators and developers in making their future decisions. This knowledge should therefore include "what changes went right; were delivered on time; at relatively low cost and met the intended objectives etc". The knowledge must also include the downsides of "what went wrong etc" so that a catalogue of DO's and DON'Ts from personal experiences is available to assist others in avoiding the pitfalls or in wasting resources on developments that do not meet the required objectives.

To enable recipients of the questionnaire to respond as quickly as possible, the information requested from you is your own direct personal experience and knowledge without unduly referring elsewhere for the answers to every question. It is hoped that gaps in your answers may be filled by answers from other contributors with knowledge of the same electricity market. It is recognised that some recipients will have access to more of this type of practical information than others and that in some areas only a few market participants will have reliable information. However it is hoped that an overall picture for each market will emerge once responses have been co-ordinated.

Some of the requested information may not apply to some markets but if other relevant information is known, but not requested here, it is hoped that contributors will include this in their replies.

The quality of the co-ordinated report will depend on the appropriate expertise for each of the **SPECIFIC AREAS : POLICY, SALES, INVESTMENT, MARKET and SYSTEM OPERATION** being accessed in every market and to assist this in happening would recipients

PLEASE COPY THIS QUESTIONNAIRE TO PERSONS KNOWN TO HAVE THE RELEVANT INFORMATION AND ASK THEM TO REPLY DIRECTLY by 31 October 1999

To Dr Graham Thomas
World Energy Council
Fifth Floor
Regency House
1 - 4 Warwick Street
London W1R 6LE
UK

OR by E-mail : thomas@worldenergy.org
gdthomas@pgen.net
Direct Tel : (+44) 1789 450069
Fax : (+44) 1789 450400

ELECTRICITY MARKET QUESTIONNAIRE

This Questionnaire is in several sections which may more easily align with a recipient's experiences, hence allowing individual sections to be sent to different experts for their specific contributions if considered appropriate.

PLEASE WOULD RECIPIENTS CONTRIBUTE TOWARDS SECTION A (Significant events from the contributor's viewpoint) AND SECTION B ACCORDING TO THEIR EXPERIENCE...

THANK YOU.....THANK YOU.....THANK YOU

The sections are :-

Section A Market Development Track Record
(Significant events from the contributor's viewpoint)

This is a free format section where you are asked to provide the significant steps in the reform from your point of view. It should start with the purpose or objectives of reform, include what economic information that is available to you and include what was significant to you; what were major successes; what were major failures; what were their costs etc.

Section B Specific Areas of Questioning

The following sections are more specific in their intended information gathering and the questions are intended to encourage you in these areas. If however, there is significant knowledge that you consider to be relevant which is not prompted by these questions then please include this in whatever form is convenient.

Government Policy, Objectives, Criteria for Success and Legislative Powers

Sales Information (Customer Satisfaction, Prices, Contracts and Demand)

Investment (Construction, Market Valuation, Viability and Subsidies etc)

**Market and System Operation (Trading Rules, System Operation and
Cross Border Flows)**

MARKET DEVELOPMENT TRACK RECORD

The purpose of this section is to capture the reform objectives, structure and significant economics of your electricity industry before liberalisation, then to record significant events (**major successes, failures and associated benefits and disadvantages**) during the “ market ” history together with their associated costs and values and their impact on electricity prices to the present date.

For many recipients the “market” history may be relatively short and indeed may be in the early stages of creation. However, this simply means that for some the completion of this questionnaire will be quicker than for others. The example below bears some resemblance to a particular market with a 10 year history. Recipients with this length of track record are thanked in advance for their participation and diligence and will be pleased to know that the advice and information that you are providing will be used to good effect in electricity markets that follow.

From the information provided it is hoped that the present position of the market may be compared with the starting position plus subsequent developments in between, with the objective of identifying the cost benefits of change. As more experience is gathered it will be possible to identify the successes and failures of certain market developments in delivering specific objectives. The information provided by recipients needs to be sufficiently detailed and quantifiable where possible to enable the different market environments to be differentiated.

Recipients are therefore asked to **BE AS GENEROUS AS POSSIBLE IN DESCRIBING INFORMATION AND ADVICE** that you would wish to pass on to future market creators and developers around the world. If the questionnaire does not prompt you for **Successes/Failures, DO's/DON'Ts** that you consider to be the important information to communicate then please provide it anyway and suggest amendments to Dr Graham Thomas on graham.thomas@pgen.com.

Please describe your electricity market development to the best of your knowledge including what you believe is the important information in a similar way as the example that follows.

EXAMPLE :- Country X

1988 Country X started its liberalisation process with a Government White Paper. Their objectives were stated to be X,Y,Z etc, benefits of x,y,z etc measured by criteria A,B,C etc Before 1988 the whole industry was state owned though corporatised into 12 regional monopoly Distribution/Supply businesses and a single Transmission/Generation business.

The Government financial position (in \$ millions) was as follows :-

	Supply	Distribution	Transmission	Generation
Debt	A	B	C	D
Annual Expenditure - Capital	E	F	G	H
- Revenue	I	J	K	L
Annual Income - Sales/Charges	M	N	O	P
- Other including taxes etc	Q	R	S	T

		Nuclear	Hydro	Coal	Oil	Gas(CCGT)	GTs	Imports
1988	Generation (TWh)	a	b	c	d	e	f	h
	Capacity (GWs)	i	j	k	l	m	n	o
	Total Sales Demand	=	?	(TWh)				
	Total Sales Value	=	?	US\$(billions)				
	Typical price to (Industry , commerce , households) = US\$ (x , y , z) /MWh							

- 1989 The Electricity Act was passed dealing with vesting of property, rights and obligations of Boards and the Regulatory framework.
The state Generation /Transmission industry was restructured into 3 generating companies (Company A = 28GW of Coal, Oil and Gas ; Company B = 18GW of Coal, Oil and Gas; Company C = 12GW of Nuclear) and a separate Transmission Company. 12 regional Distribution Companies already existed.
Market Design for a Generating Pool and Wholesale Settlement commenced.
All generators will bid daily to be despatched and to set a system marginal price for all generation. Wholesalers and customers larger than 1MW may buy from the Pool.
During first 9 months typically 100 staff were involved but most of design was aborted.
Over next 6 months 200 staff designed and built the prototype used to start the market.
- 1990 Pool Market started using prototype. More auditable and robust software was introduced 6 months later. The Pooling and Settlement Agreement contained an outline plan for further market liberalisation and development over the next 8 years.
Total costs to introduce market are estimated at US\$ 2? billion .
Being state owned companies at this stage the cost was paid by the Government.
Distribution Companies privatised 9 months later for a total cost of US\$ 6? billion.
- 1991 60% of Companies A and B is privatised at a cost of US\$ 3? billion.
First new entrant IPP signed N-year PPAs with Distribution Companies.
- 1994 Remaining 40% of Companies A and B privatised at cost of US\$ 3? billion.
Customers larger than 100kW can purchase from the Pool. Cost of Market development for this is US\$ 2? billion. 70?% of this was spent by the private distribution companies which could recover costs through their regulated income. The rest was a cost on private supply companies. This development took over 2 years plus 100 extra central staff for the design.
- 1996 60?% of Company C is privatised for cost of US\$ 3? billion.
- 1998 Government approve a windfall tax on the electricity industry totalling US\$ 3? billion.
Government implements policy to stop Gas plant construction.
- 1999 All customers can purchase from the Pool.. Cost of this development is US\$ 3? billion.
60?% of this cost was within the Distribution/Supply companies and was an allowable regulated cost passed through to the customers. The rest was a cost on the private supply companies competing at that time. This development took over 4 years using typically an extra 200 experienced central staff.
- 2000 Regulator proposes fundamental change of Market design at a total cost of US\$ 2? billion.
A similar split of costs between regulated companies able to recover costs and private suppliers who may or may not be able to recover costs under competition.

OTHER COSTS (Apart from the major changes identified above)

Annual Pool costs for development have been typically US\$ 25 million using 80 staff

Annual Pool costs for production have been typically US\$ 60 million using 300 staff

Annual Regulatory costs have been typically US\$ x million using 400 staff.

ELECTRICITY PRICES over the period from pre-market operation have shown :-

30% reduction for large industry ; 25% reduction for commerce and

25% reduction for households. Prices are typically US\$ X,Y,Z /MWh for 1999.

Total Sales of electricity (today) = 290? TWh

Total value of Sales (today) = US\$ 30? billion

GENERATION GROWTH 1991 1992 1993 1994 1995 1996 1997 1998 1999

New entry (GW)	a	b	c	d	e	f	g	h	i
Investment total	A	B	C	D	E	F	G	H	I
Demand total (TWh)	270	275	270	280	285	280	285	290	295
Demand Peak (GW)	48	48	47	47	49	50	49	48	49

GOVERNMENT POLICY, OBJECTIVES, CRITERIA FOR SUCCESS AND LEGISLATIVE POWERS

Government objectives are often high level and can vary with time. The criteria for measuring the success or failure of a particular market reform or development are often ignored and unpublished. However debate prior to market reform is often very lengthy and some statements are published to identify the Government objectives. Statements on expectations are also made which may be used as criteria to judge later success or otherwise.

Eventually new legislation is passed which may add to some existing laws such as competition or anti-trust laws. Privatisation and Restructuring often require new legislation on property rights and allocation etc. Regulatory powers are normally found in an Electricity Act passed specifically to create liberalised and regulated sectors.

Specific questions to address some common objectives :

The following questions are aimed at collecting specific information to address individual objectives. A particular objective or question will be given first and then more detailed questions which aim to collect information that can be used to answer the particular question.

You may either answer the high-level questions directly if that seems more sensible to you ,
OR please provide the answers to the detailed questions and please add any other relevant information that you consider to be necessary to answer the question as it relates to your electricity market.

1. General :

What (were/are) the Government's Main Policy Objectives, their criteria for success and what specific actions or measures (did/do) they propose to deliver these?
From operational experience estimate to what extent these objectives have been met ?
(ie Successes/Failures and at what cost and time)
Have objectives been changed or new ones introduced ? Why ?
Have any new actions or measures been taken to improve success ?

Specific :

(1.1) What specific measures (did/does) the government propose to reduce its investment obligations and to attract private investment ? What has been the result ?

(1.2) How do you maximise the value of assets on privatisation ?

From your experience, please provide the factual information and indicate which factors tended to increase value and which tended to decrease value ?

Consideration may be required of the following factors:-

The length of contractual agreements (PPAs, Fuel contracts etc)

The present and future form of competition (Pool?, Despatch Rules , Third Party Access etc)

The forecast of market prices and charges (or Governments forward plan for prices etc)

The risks from Government or Regulatory powers to change market conditions

The phasing, timing and size of sales etc

(1.2.1) What other factors were important and why in your privatisations ?

(1.3) What are the options to achieve internationally low electricity prices ?

For those states with this as an objective, what action was taken and what factors were included in any impact study ? (eg exports/imports, unemployment, taxes, loan repayment)
Should electricity prices be set by Government design (Energy policy with or without cross-subsidy), OR left to free market forces to deliver, OR a combination OR alternative ?

(1.4) How do you ensure reliable and adequate supplies of electricity to meet demand ?

What has been the experience to date ? (Success or Failure ?) (DO's and DON'Ts)

A particularly important design feature of any market is the allocation of powers and obligations that exist in the market. These are captured in the state legislation, regulatory powers, industry operating codes and licences etc.

(1.5) What are the influential powers in your market ?

(1.5.1) What are the most important clauses to be included in any relevant Anti-trust laws, Government Legislation (eg Electricity Act) and industry Licences ?

Please describe briefly the laws that already existed and then what was approved specifically to introduce the liberalisation ?

(1.5.2) What modifications or additions have been approved subsequently ?

(1.5.3) What major omissions or deficiencies were identified since the initial liberalisation ?

(1.6) What were the powers and role of the Regulator at liberalisation ?

(1.6.1) Success or Failure ? What deficiencies have been identified ?

(1.6.2) What changes in the powers or role have been approved since ?

(1.6.3) Were these changes expected beforehand or have different priorities emerged ?

(1.6.4) How are regulatory resources/staff distributed across the sectors ? Total staff ?

(1.6.5) What is the annual regulatory cost/budget ?

(1.7) What are the benefits and disadvantages of Industry Restructuring ?

(1.7.1) Can these be quantified ?

(1.7.2) Can the benefits be gained otherwise ?

(1.7.3) Can the disadvantages be attributed to other causes ?

(1.7.4) Were the benefits and disadvantages forecast beforehand ?

(1.7.5) What are you recommended DO's and DON'Ts ?

(1.8) What are the benefits and disadvantages of Privatisation ?

(1.8.1) Can these be quantified ?

(1.8.2) Can the benefits be gained otherwise ?

(1.8.3) Can the disadvantages be attributed to other causes ?

(1.8.4) Were the benefits and disadvantages forecast beforehand ?

(1.8.5) What are your recommended DO's and DON'Ts ?

SALES INFORMATION (Customer Satisfaction, Prices, Contracts and Demand)

2. What has been Customer Reaction to liberalisation and resulting Standards ?

- (2.1) Has customer satisfaction increased or decreased regarding :-**
 - (2.1.1) Prices.....and what are their expectations over the next 5 years ?
 - (2.1.2) Service levels and standards ?
 - (2.1.3) Reliability and disconnections ?
- (2.2) How has supply reliability to customers changed since liberalisation ?**
Please comment on planned and unplanned loss of supply separately.
- (2.3) Have safety standards in generation, transmission and distribution improved or deteriorated and by how much since liberalisation ?**
- (2.4) What value added services are now offered to customers ?**
- (2.5) Has branding been introduced ? Is it effective ?**
- (2.6) How many customers (numbers and percentage) have switched on a net basis, one year, two years, three years etc after customer choice was permitted ?**
- (2.7) What types of tariffs/payment methods etc have been newly introduced to retain or expand the customer base ?**
- (2.8) What has been the experience of introducing customer choice ?**
 - (2.8.1) What demand levels and timing of introduction was used ?
 - (2.8.2) What were the major practical difficulties and costs ?
 - (2.8.3) How have the changes affected the industry companies ?
- (2.9) What would the customer say were the Successes/Failures to date ?**

3.What have been the key Market Price trends since liberalisation

- (3.1) Please provide any historical records which demonstrate the variability of electricity prices commencing from just before liberalisation, through the period of market development to the present day on :-**
 - Annual Average Price for Pool, Wholesale, Industrial, Commercial, Household etc
 - Monthly Average Prices paid (for the above customer sectors).
 - Highest price within year for short term or spot deals
 - Lowest price within year for short term or spot deals
 - Unbundled Transmission and Distribution charges (transport and connection)
- (3.1.1) How long do price spikes and trough last for , and how frequent ?**
- (3.1.2) To what extent has a cheaper supply of natural gas affected the price of electricity ?**

(3.2) What examples of market dominance by individual, or a group of, companies in the setting of any of the individual components that determine the total price of electricity to the end customer can you describe, giving some financial quantification of the action? (eg generation prices, behind constraints, ancillary service prices, stand-by services, Transmission charges, wheeling and connection charges, distribution and connection charges, other service charges etc)

(3.3) What solutions were identified to prevent this dominant behaviour and how long did it take to introduce them into action ?

4. What Contract Types are used within the market ?

(4.1) What contract types are available for the sale and purchase of electricity ?

(4.2) What volume is traded by each of these contract types ?

(4.3) What percentage of the annual demand volume is traded through a Pool, a Power exchange or via bilateral contracts ?

(4.4) What information can you give on the different tariff designs available between suppliers, distributors and customers ?

5. What effect has there been on Demand Growth patterns since liberalisation ?

(5.1) What demand growth information can you provide on the different sectors of Industrial, Commercial and Domestic loads ?

(5.2) What evidence is there to indicate that electricity is being used more efficiently ?

(5.2.1) Is the price high enough to encourage efficiency ?

INVESTMENT (Construction, Market Valuation, Viability and Subsidies etc)

6. Please reply specifically to the following Investment and Financial Information requests and add any other major observations from your own market ?

(6.1) Which sectors have seen increased /decreased investment since liberalisation ?

Please provide the following new investment, not including acquisition :-

	Year 1	Year2	Year N	since liberalisation
Generation (US\$? billions)	?	?		?	
Generation (GW Commissioned)	?	?		?	
Transmission (US\$? billions)	?	?		?	
Distribution (US\$? billions)	?	?		?	

(6.2) Following any unbundling/disaggregation of activities which activities are profitable and which are not profitable ?

(6.3) Which activities should not be incentivised with a profit motivation ?

(eg ISO, Market Operator, Supplier of energy pool, Regulator) ?

(6.3.1) How should such activities be encouraged to become efficient ?

(6.4) Is there any evidence to indicate minimum viable sizes for certain sectors ?

(eg independent distribution, co-ops with or without generation,
small independent generation)

(6.5) What sectors have been purposefully subsidised against market competition ?

(eg renewables, rural users etc)

(6.5.1) What has been the observed growth against any target plan ?

(6.5.2) How are the subsidies/inducements structured ?

(6.5.3) What has been the experience with renewable energy sources and what level of subsidy is needed ?

(6.6) Can alternative investment options compete fairly ?

(eg Transmission or Distribution interconnection against generation expenditure , reactive power generation against static compensation, demand management against generation , local generation against wheeled electricity or imports etc)

(6.7) What changes in fuel usage, if any, can be attributed to liberalisation ? (eg Indigenous)

(6.8) What has been the impact on investment in general of access to cheaper supplies of natural gas ?

(6.9) How has the Asset Value of both State and Private Companies changed over the period since privatisation, liberalisation or market introduction ?

What key indicators, such as share prices, can you provide which are easily available ?

(6.10) Have electricity prices been deliberately depressed or cross-subsidised in your state ? If so, for how long how much, who benefited and who was effectively paying for this ?

(6.10.1) If so, do you consider that there is the potential for future reductions following a liberalisation reform whilst providing acceptable rates of return on investments ?

(6.10.2) What rates of return would you expect ?

(6.11) HOW HAVE STRANDED COSTS BEEN CALCULATED ?

Many countries are facing the prospect of having to determine what investments may be considered as *stranded costs* which may not be recoverable following a proposed liberalisation change. A description of the specific calculation method adopted in your state would provide valuable guidance, together with the form of agreement (eg Is it a negotiation between parties dependent on various forecast assumptions ? If so, please provide details).

(6.11.1) Please provide examples of which investments were considered to fall within the definition and which were not, together with the relevant reasons.

Please reply in whatever manner that you consider best provides the advice.

(6.11.2) Can you comment on or add to the following Factors that may be relevant to the determination of stranded costs :-

Length and prices in existing agreements (eg power and fuel purchase, transport , loans etc)

Forecasts of above products at market prices, particularly electricity and fuel

Generation capacity and demand level forecasts

New entrant capacity and price levels

Government and Regulatory intentions etc

Use of market scenario modelling

(6.12) How can existing Power Purchase Agreements be Managed through a change ?

Governments or State companies may already hold a number of agreements prior to a proposed change such as privatisation, restructuring or the introduction of a market.

Please provide any relevant experience which demonstrates successful or unsuccessful methods of dealing with the transfer or renegotiation of these agreements with regard to the specific change in the industry.

(6.13) What examples of Successes and Failures can you provide in the area of investment ?

(6.14) What are your DO's and DON'Ts in this area?

MARKET AND SYSTEM OPERATION

7. How stable are the Market Trading Rules in your market ?

(Here the definition of Market Trading is taken in its widest sense to include any influence on electricity price and volume, and hence connection, production and despatch)

(7.1) Please provide a historical account since liberalisation of significant changes to the trading rules or pricing mechanisms which affect trading volumes or prices directly or indirectly.

(This may be captured in your track record but please ensure the detail is adequate for these purposes)

Please include the following information in your description :-

Who has powers to implement change ?

What is the approval process ?

How long should and did it take ?

How frequent have significant changes happened ?

How large was the effect on price and volume etc ?

Who initiated the proposed changes ?

Who benefited from the change and by how much ?

Who funded the change and how much did it cost to implement ?

(7.2) What is your experience of a Power exchange ?

(7.2.1) Is it a monopoly, who operates it, and for what purpose ?

(7.2.2) Is it independent ? Have there been problems because of this ?

(7.2.3) What were/are the set-up costs and timescales, and annual costs and charges ?

(7.2.4) What are the system and staffing requirements ?

(7.2.5) What are the expected annual development costs ?

(7.2.6) What is the forward Development Plan and Budget for N years ahead ?

(7.2.7) What are the associated total costs that the industry and others have to spend to interface with this development ?

(7.2.8) What volumes (TWhs and Percentage of annual demand) and Total Revenue value has the Power Exchange traded over the last 5 years ?

(7.2.9) What are the DO's and DON'Ts in creating a Power exchange ?

(7.3) What is your experience of an Electricity Pool ?

(7.3.1) Is it a monopoly, who operates it, and for what purpose ?

(7.3.2) Is it independent ? Have there been problems because of this ?

(7.3.3) What were/are the set-up costs and timescales, and annual costs and charges ?

(7.3.4) What are the system and staffing requirements ?

(7.3.5) What are the expected annual development costs ?

(7.3.6) What is the forward Development Plan and Budget for N years ahead ?

(7.3.7) What are the associated total costs that the industry and others have to spend to interface with this development ?

(7.3.8) What volumes (TWhs and Percentage of annual demand) and Total Revenue value has the Pool traded over the last 5 years ?

(7.3.9) What are the DO's and DON'Ts in creating an Electricity Pool ?

(7.4) What form of market do you think is most suitable for your transmission area ?

Consider activities of construction, production and physical despatch, Pool, Power Exchange, transport , supply/customer choice AND TOTAL COST AND BENEFIT.

8. Have System Operation Requirements been achieved ?

The purpose of this section is to identify any concerns over standards and the operation of the Transmission/Distribution network as a result of liberalisation etc.

If the following questions do not raise the issues that are of concern to you, then please describe the issues directly.

- (8.1) Did Operating Codes exist prior to liberalisation that specified required Transmission and Distribution standards? What are their references ?**
 - (8.2) Since liberalisation which standards have not been met at some time subsequently and during which years?**
 - (8.2.1) What is the value of investment needed to meet the standards that were not met ?
 - (8.2.2) What action has been taken to solve any shortfall against standards ?
 - (8.3) Has sufficient generation capacity been commissioned on time to meet expected demand growth at all times since liberalisation ?**
 - (8.3.1) If not, what aspects of the market environment were considered to be deficient and what has been the remedy ?
 - (8.4) Is there a single despatcher of generation plant in the market ? (eg Grid Operator)**
 - (8.4.1) Is the Despatcher independent ? Have there been problems because of this ?
 - (8.5) Please provide a description of the despatch rules for generating plant identifying the order of priority, on what basis and who makes the decisions for plant operation ?**
 - (8.5.1) If Hydro plant operates could you please describe the relative priorities in the order of despatch given to generation, irrigation, flood prevention, or any other duties ?
 - (8.5.2) To what extent is despatch on an environmental basis as opposed to a cost basis ?
 - (8.6) What percentage (or GW capacity) of inflexible plant (eg Nuclear, PPA must-run) is acceptable for system stability control to be maintained and for the management of transmission constraints etc ?**
 - (8.6.1) OR, what percentage/capacity of flexible plant is needed for which duties ?
 - (8.7) What is the total annual cost of transmission constraints (eg decongestion costs) and how has this varied through the period of liberalisation ?**

How are these costs allocated and recovered ?

How is the operator incentivised to construct lines efficiently ?
 - (8.8) What DO's and DON'Ts from your market would you recommend in the areas of Transmission, System Operation and Despatch of generation ?**
- ## **9. What has been the impact of Cross Border Electricity Flows ?**
- (9.1) What have been the benefits and disadvantages of cross border flows ?**
 - (9.1.1) Who has benefited and who has not, and by how much ?
 - (9.2) How are conflicting objectives such as the environment versus competition resolved in cross border flows ?**

APPENDIX 2. LIBERALISATION IN ENGLAND & WALES

Background

Liberalisation of the electricity industry in England & Wales took place relatively quickly over three to four years leading up to 1991, by which time the main privatisations had been completed. The UK government held serious debates about liberalisation during 1988–89, introduced a pool market in 1990, and restructured and privatised the state-owned corporate businesses in 1990–91.

However, this restructuring and introduction of a competitive market in England & Wales contrasted with the lack of such developments in Scotland (which has a separate electricity supply system). There was no restructuring of the two vertically integrated state-owned Scottish utilities, Scottish Power and Scottish Hydro, and no competitive pool was introduced. Scotland's electricity supply has continued to be dominated by these two utilities, which were privatised as regional monopolies. They have successfully resisted competition and prevented the construction of competing IPPs, because of their vertical integration and control of the interconnector between Scotland and England. The following description now applies only to the electricity industry England & Wales, and should not be generalised by reference to the UK.

By the 1980s the UK government had already corporatised most state-owned industries, with senior executives appointed by government. Then, throughout the 1980s, the government pursued a policy of privatisation, transferring government corporations into private ownership. Several state monopolies, including telecommunications and gas, were privatised as single companies. These industries were open to competition by law, but new entrants were slow to materialise. The benefits of introducing competition at the outset were therefore becoming apparent, and the decision to restructure the electricity industry before privatisation was a first. Another initiative was the concept of introducing a bidding pool for competition in generation. These features created unique circumstances for a privatisation, and as a result it was viewed very cautiously by the investment community.

Until the 1990s, generation and transmission in England & Wales were the responsibility of the government-owned Central Electricity Generating Board (CEGB). Twelve regional electricity boards (also state-owned) were responsible for distribution and supply. The CEGB sold electricity via a bulk supply tariff to the regional boards. Some large industrial users were subsidised by being supplied at prices that hardly covered costs.

Being essentially an island system with only DC connections to France and Scotland, control of frequency and voltage on the grid system is a significant concern. In the absence of significant hydro generation, control was provided mainly from coal-fired plant, although 2 GWe of pumped storage capacity had been constructed with system control as the main objective.

Moderate demand growth in the 1970s had required continual commissioning of 2000 MWe coal and oil power stations, housing 500 MWe and then 660 MWe units. The later 1970s were dominated by the construction of large nuclear stations

and also the 4000 MWe Drax coal station. With there being between two and four UK plant manufacturers at different times, plant designs tended not to be repeated and nuclear construction times became long, exceeding 10 years in some cases, as technological problems were encountered. Availability was typically below 60% for nuclear plants, yet the security of the grid system in meeting demand was among the highest anywhere in the world, with a design margin of 27% in generation capacity.

During the 1980s demand growth was relatively low at 1–2%, yet the 1980s started with a continuing large-scale construction programme. Generation from coal remained at nearly 80% of the total, supporting a large government-owned indigenous coal industry. Natural gas was not permitted to be burned for baseload generation, and was being flared off from North Sea oil rigs. High design standards for generating units in the UK made it difficult for UK manufacturers to compete abroad, because of associated costs. So when the construction programme stalled to a halt in the mid 1980s, a review of capital investment decisions was already overdue. After the early 1980s the CEBG's debts to the government from the previous period of heavy construction investment had been repaid, but electricity price levels were maintained to raise government funds. Typically, £200–300 million (US\$300–450 million) was raised for the government annually.

By 1990 demand was about 265 TWh and was met by around 300 centrally despatched generating units. Available capacity was around 56 GWe for a winter peak demand of 47 GWe. In addition, there was a 1 GWe interconnector to Scotland and a 2 GWe interconnector to France. Generation output was 78% coal-fired, 17% nuclear, and a little hydro (2 GWe pumped storage). There was no baseload gas-fired generation.

By the end of 1999, peak demand had risen to over 50 GWe, but available generating capacity had remained at 56 GWe. Although 19 GWe of plant, mainly coal but some oil, had been closed or retired, it had been replaced by baseload gas-fired plant. Generation was now 34% gas, 30% coal, 25% nuclear and 11% other. Fuel diversity was strategically more robust, although the electricity and gas markets had become interdependent, with power generation being by far the largest consumer of gas. By year-end 2000, gas generation was approaching 40%.

As the largest consumer of gas, the electricity industry is now closely linked to gas prices. During 2000 UK customers have complained at modest rises in electricity prices during the summer and also rises in gas prices resulting from the rise in oil prices but also resulting from the effect of the gas interconnection between UK and Europe. With lower gas prices in UK than in Europe, the incentive is to export gas to Europe. However, as usual, the effects of interconnection are to raise prices in the exporting country and to reduce prices in the importing country. As Europe becomes more interconnected in both gas and electricity, the effect is to converge prices with some customers paying more and some less. This is a common problem, emerging now in electricity worldwide.

Historical Drivers for Change

Reform of the electricity industry had been considered as early as 1983, when the government had questioned its efficiency and the quality of its major investment decisions. The 1983 Energy Act was intended to bring private investment into electricity production and supply, to provide competition for the state-owned

monopolies. It obliged state-owned regional electricity distributors to buy power from independent producers, and to give independent suppliers of electricity access to the system. The conditions, payments and charges were, however, dictated by the state monopolies, which had no incentive to encourage access to the system. There was no independent regulator to deal with disputes. In most respects, the Energy Act 1983 was a failure, but it provided a lesson to the government.

On the other hand, privatisations of other state monopolies since the early 1980s had been successful and well-received by the investment community and individual investors. Individual investors had seen their investments grow, and the only drawback had been the slow pace with which independent competition had emerged. The government slowly realised that the dominance of the newly privatised companies gave them many incumbent advantages over newcomers. This pleased the millions of new shareholders but did little to encourage competition and to improve commercial efficiency. In addition, in some industries the relationship between the regulator and the industry was either too cosy initially or became openly aggressive. The privatised monopolies were reluctant to accept that they were no longer the means of implementing government policy.

Government Policy and Objectives

The government's primary objective in privatising the electricity industry was to further the strategic aim of reforming the structure of the British economy by introducing competitive pressures, and by ensuring that capacity and investment decisions related to market conditions and not to the dictates of government. Subsidiary objectives included the raising of staff morale and incentives by enabling them to be shareholders, and the improvement of safety conditions by separating plant and system operators from the safety regulator.

A government White Paper published in February 1988 outlined its policy for electricity and emphasised the following principles:

The proposals set out in this White Paper will secure a more efficient and economic supply of electricity, by building on what is best in the industry and ending what is wrong with the present structure.

- 1. Decisions about investment in power stations will be driven by the distribution companies and so will reflect the needs of customers.*
- 2. Greater competition will create downward pressures on costs and prices, and ensure that the customer, not the producer or distributor, comes first.*
- 3. Customers will be given new rights, not just safeguards.*
- 4. Management will have more freedom to use their initiative within a clear regulatory framework.*
- 5. The security and safety of electricity supply will be maintained.*
- 6. Investment plans will be subject to commercial tests, and the industry will have access to private sector finance.*
- 7. Employees will have the right to own shares in their industry, and customers will also have the opportunity.*

A modern competitive industry will be created, widely owned by the public, and more responsive to the needs of customers and employees. The industry will have a better chance of meeting electricity demand at minimum cost. There are real benefits in prospect for the customer, employee and the economy.

These principles underpinned the restructuring of the electricity supply industry in England & Wales, the creation of the electricity pool, the plans for phased opening up of supply competition, the regulatory framework set out in the licences, and the overall development of the market from 1990 for the following eight years.

However, the principles sometimes became difficult to follow when setting up successor arrangements for the nuclear industry, the coal industry, and large intensive electricity customers. All of these received special treatment when the industry was owned by the state.

Initially, nuclear power stations were removed from the privatisation, although a group of more modern nuclear stations has since been privatised. A non-fossil (i.e. nuclear) levy was payable by all fossil generators to cover the costs of decommissioning nuclear plants, which had been justified on the grounds of fuel diversity. Prior to the privatisation of the fossil generating companies, they were obliged to enter into four-year deals to purchase prescribed volumes of coal at an agreed price. When these contracts ended the government tried unsuccessfully to pressurise the electricity industry into extending the same terms of the deal, in order to help the coal industry. Large electricity consumers who had bought electricity at or below the marginal cost of production were offered a one-year transitional deal, which was subsequently extended in a modified form for a further year. At the end of this transition, large customers were able to claim that the introduction of competition had caused their electricity prices to rise by 25%.

In contrast to what may have been the case in other countries, maximising asset valuation was not a primary objective. Had it been otherwise, it would probably have made sense to privatise the industry as a single entity, as in previous privatisations of other industries. However, when it came to vesting day every effort was made to make the sale of shares on the open market a success.

The first to be privatised, in 1990, were the 12 regional electricity boards, which became regional electricity companies (RECs). These were floated together, and their shares traded at a premium in excess of the government's target immediately, partly due to underlying Stock Exchange movements. Subsequent press statements accused the government of selling at too low a price. To reduce the risk of failing to maximise proceeds from the subsequent sale of the generators, the government only sold 60% of the stock of National Power and PowerGen at initial flotation in 1991. Sale of the balance took place four years later, by which time the share prices had risen, significantly outperforming the equity market. This became a common feature of privatised stocks in the first five or six years following privatisation, and in the case of electricity companies it was to last until the beginning of 1999.

Liberalisation Progress

Following the ineffectiveness of the 1983 Energy Act, the first positive steps for electricity liberalisation were made in 1987, the year after the privatisation of the gas industry and the first phase of gas supply competition. In that year, a draft government White Paper, "Privatising Electricity", announced the intention to privatise the state-owned electricity industry and to introduce competition to production and supply of electricity. At first, this was strongly opposed by the state industry and it was consistently opposed by the trade unions.

In 1988 the government approved the White Paper. The CEEB's resistance to being split up disappeared rapidly once senior executives had been chosen for the companies, and staff and station allocations followed quickly.

In 1989, the Electricity Act was passed dealing with the regulatory framework, and the vesting of the property, rights and obligations of the 12 distribution companies to be formed from the regional electricity boards, and of the restructured successor companies to the CEEB. Initially, the CEEB was to be split into three. A transmission company, the National Grid Company (NGC), would own the grid together with the 2 GWe of pumped storage (on the grounds that it was operated for system control). Generation assets would be split between two companies, National Power and PowerGen, the former large enough (with 70% of capacity) to accommodate the liabilities of the nuclear power stations.

However, shortly before the market commenced operation the decision was made to withdraw the nuclear stations from the initial privatisation, leaving a remnant state-owned nuclear company. Thus, three generating companies were created: National Power (28 GWe of fossil plants), PowerGen (18 GWe of fossil plants) and Nuclear Electric (12 GWe of nuclear plants). Some of the nuclear stations were eventually sold off several years later.

The Act made the 12 regional electricity boards into regional electricity companies (RECs), which were distribution and supply businesses. It also created the regulatory office of Director General of Electricity Supply, with statutory responsibilities for, among other things, encouraging competition in generation and supply, and examining the financial standing of licensed companies. The main participants in the industry, including new entrants, would be required to be licensed in their field of activity (generation, transmission, distribution or supply).

Also in 1989, market design for the generating pool and wholesale settlement commenced, though initial position papers had been put forward in 1988. The market design included all generators bidding daily for despatch and to set a system marginal price. Wholesalers and customers larger than 1 MWe would be able to buy from the pool.

During the first nine months of 1989 typically 100 staff were involved in pool development, but most of the initial design was scrapped. Over the six months leading up to the end of March 1990, 200 staff designed and built the prototype system which was used to start the market.

At the end of March 1990, assets were vested in the restructured state companies, which commenced commercial operation.

The British coal industry was protected by fuel contracts signed with National Power and PowerGen for the following four years with agreed prices and delivery volumes. The two generators also signed four-year electricity contracts at agreed prices with all of the 12 RECs to cover the expected coal usage. The government brokered these contracts before vesting on 30 March 1990.

The nuclear generator, retained by the government, was to receive a levy of 11% per annum on all sales to cover future decommissioning costs. The 11% was also given reluctantly to imports of Scottish and French electricity, since France threatened legal action under European law if it was not given the same benefits as Nuclear Electric. This considerably reduced the revenue to Nuclear Electric, and the levy had to be continued for more years as a result.

NGC, with its 2 GWe of generation, was transferred into the shared ownership of the RECs, which were themselves privatised at the end of 1990 for a total realisation of around US\$6 billion. However, each REC was privatised with debt owed to the government, with the total debt being around US\$3 billion. The government retained a "golden" share in each REC to allow control of future ownership. The RECs were allowed to own generation up to a limit of 15% of their own electricity requirement. Within a few years this limit was raised to 25%.

At midnight on 30 March 1990 the electricity pool commenced trading, and the state-owned generating companies began to develop commercial track records in preparation for privatisation. Supply competition for the 5500 customers taking over 1 MWe started immediately, as these customers could buy directly from the pool or from wholesaler suppliers.

The pool started operation using prototype software and without electronic trading and settlement communications in place. Systems mainly used paper input and output to start with, such was the desire to meet the starting deadline. More auditable and robust software was introduced six months later, in September 1990.

The electricity market, including the sale and purchase of electricity through the pool, was governed by a multilateral agreement between all participants. The power of the regulator was one of veto over industry proposals. The Pooling and Settlement Agreement contained an outline plan for further market liberalisation and development, which could not be included initially, over the next eight years. The pool published prices for the following day against which contracts could be agreed and consumption decisions could be made.

Total costs to introduce the market, including company internal costs, are estimated at around US\$2 billion, but as the companies were state-owned at this stage the cost was paid by the government.

In 1991 the government privatised 60% of National Power and PowerGen, realising around US\$3 billion. Between them the two companies held government debt of around US\$1.5 billion, and the government again kept a "golden" share in each company.

The government had considered several options for the privatisation, including trade sales. Trade sales would have allowed the government to understand the companies' values better, and would also have encouraged the companies, in particular the smaller PowerGen, to accept a level of debt on their balance sheet at flotation. This would have discouraged a predatory company from immediate asset stripping by breaking up the company to realise a profit. It would also have limited company borrowing and focused the companies on repaying debt and interest to the government.

However, these privatisations, as others, were eventually carried out by public offering, with reserved allocations for company staff (at discounted prices), for the public, and for major investors. The latter two categories were over-subscribed some three times and applications were scaled down accordingly.

In October 1991, the first major new power station not owned by the ex-state companies opened. It was a combined cycle gas turbine (CCGT) station on the site of a redundant CEGB coal-fired station. The output was contracted to some of the RECs via long-term (about 15 years) power purchase agreements (PPAs).

During 1992–93, the construction and commissioning of further CCGT plants, with capacities in the range 400–1000 MWe and with long-term take-or-pay contracts for gas, started the so-called “dash for gas”. Although sufficient coal-fired capacity existed, with up to 50% of total demand becoming open to competition in 1994 and the original four-year PPAs with National Power and PowerGen ending in that year, the RECs began to invest in IPP equity and to sign PPAs with IPP developers. This was a strategic decision by the RECs to build up their own capital assets, instead of contracting for power with the small number of existing generators. The RECs wished to diversify from their regulated distribution and supply businesses, including into the electricity generation sector.

The IPP stations were established with long-term gas contracts (e.g. 20 years) and long-term PPAs (e.g. 10–15 years). The gas contract risks and the plant availability risks were transferred to the RECs through the PPAs, so that these IPPs were low-risk projects for the owners and operators. Managing the take-or-pay gas contracts required the stations to operate at baseload, and so the RECs had to ensure that they were despatched by the grid operator. This was achieved by bidding zero prices into the pool, which had a downward pressure on pool prices.

This also left the coal-fired generators, National Power and PowerGen, with little support from other generators in their attempts to hold up energy prices for the coming negotiations in 1994. It also focused regulatory attention on these two generators, and to some extent away from the monopoly distribution businesses. Indeed, attention during the first few years of pool operation was almost entirely on pool price spikes and the bidding behaviour of the two main generating companies, with several regulatory reports written each year.

From April 1994 customers larger than 100 kW could purchase directly from the pool or from alternative suppliers. To achieve this development took over two years, plus 100 extra central staff for the design. The cost of this further liberalisation was around US\$2 billion. The distribution businesses of the RECs, which could recover costs through their regulated income, spent about 70% of this. However, the rest was a cost on the supply companies entering the market. Competition in supply came from the supply businesses of the RECs, which were no longer restricted geographically and could compete against each other, and from supply businesses created by the major generating companies. Later, other supply businesses, including those set up by gas suppliers, entered the market.

The technical and commercial aspects of introducing competition in supply were challenging, and there were many problems associated with the process. The introduction of competition in the above 100 kW market in 1994 was plagued with data-handling difficulties, which continued for 18 months. Much of the problem resulted from regulatory pressure to expand the market to the 55 000 customers in this category before the necessary meters had been fitted and systems had been checked. Billing could not be performed accurately for over a year, and problems had to be solved by bilateral agreements between suppliers and customers outside the pool. With hindsight this could have been a disaster. After twelve months, more database errors were being introduced than were being corrected, and the resulting poor publicity was reflected onto the industry rather than onto the regulator.

The very largest customers, who had enjoyed subsidised tariffs from the state-owned industry before competition was introduced, regularly pronounced that they were not satisfied with prices in the market. They drew attention to the

operation of the pool, which they alleged was dominated by generating interests, and too few at that. Their complaints were voiced loudly and regularly, and with considerable effect. Only the smaller customers entering the market received the benefits of supply liberalisation, but the costs were shared across all (including the largest customers).

Pool prices had out-turned low in 1990, the first year, for several reasons. Prices rose towards 1993, and as a consequence the regulator obtained undertakings from National Power and PowerGen to cap time-averaged pool prices at £24/MWh (about US\$36/MWh) for 1994–95 and 1995–96, under threat of regulatory action aimed at breaking them up. This agreement annoyed the other generators, particularly baseload plant (since peaking generators are remunerated closer to demand-averaged prices, which may be higher). Estimates of the losses to the government-owned nuclear company were around £500 million (US\$750 million) per annum, at a time when it was trying to prepare for privatisation.

National Power and PowerGen demonstrated their ability to meet price targets by delivering £24/MWh exactly, together with a demand-averaged price of £26.4/MWh. Because of higher prices in the first half of the year, prices during the last three months (during the winter period of highest demand) had in some half hours to be bid below costs in order to meet the annual target. This produced an almost inverse relation between price and demand, which caused confusion among external analysts and observers.

However, the price cap agreement made very good commercial sense from several viewpoints. Negotiation was also taking place for further four-year coal contracts, with National Power and PowerGen under pressure to support British Coal with a “reasonable” revenue stream as the government prepared to privatise British Coal. Back-to-back with these coal contracts were electricity purchase agreements between National Power and PowerGen and the RECs. The latter were also under duress from the government as it prepared to sell its remaining 40% ownership of the two generators. At the same time, the RECs were undergoing their first regulatory review, and the regulator was reluctant to see prices not being reduced as fast as they might otherwise be. Overall, the government had an interest in maintaining higher prices, although the regulator did not accept the political objective of supporting the coal industry.

In 1995 the remaining 40% government stake in National Power and PowerGen was privatised. This realised around US\$3 billion, helped by the share price growth since the initial sale. British Coal was privatised with a realisation of around US\$1.2 billion.

By this time the regulator had become dissatisfied with the NGC's ownership of the 2 GWe of pumped storage generation, since it was clearly not being used solely for system control duties. Its profitable operation required a daytime to night-time price ratio of about 3:1, to recover the overnight costs of pumping. Its operator therefore had an incentive to raise peak prices, yet it was owned by the market operator and purchaser of ancillary services, which could sign lucrative contracts with itself. Similar internal contracting between regulated businesses and wholly owned service providers was common in the privatised water companies. The NGC, owned by the RECs, sold the pumped storage power stations to a US company for over US\$1 billion. UK companies, requiring rates of return at the time approaching 20%, could not compete with this price.

Regulatory control to date had been light, with the regulator using its own "RPI-x" form of regulation on the income of the monopoly businesses (based on the retail price index (RPI) minus a percentage (x) set by the regulator for each business). Initially values of x had been low, typically 1–4% for the first four years, so that privatisation prospectuses could indicate light regulation. The value of x set by the regulator could be appealed to the Monopolies and Mergers Commission (MMC), but the only challenge was by Scottish Hydro, which won a reduction in the regulator's proposed increase in x. However, competition in the generation sector had already demonstrated that large cost savings were possible, accompanied by reductions in the workforce of around two-thirds. This was reinforced when the two largest generating companies, National Power and PowerGen, agreed to the pool price cap yet could continue to increase shareholder dividends through cost reductions.

For the first regulatory review of the distribution businesses the regulator had settled on x remaining in single figures. However, values consistent with the efficiency gains in generation would have been over 20%, and it was quite clear to industry experts that to incentivise monopolies to the same degree as the competitive sector would require such values. What is more, investors in these early years perceived little difference between the competitive and regulated sectors.

In March 1995, the government's control over ownership of the RECs via its "golden" shares was given up. This started an open season on these companies, with mainly US companies interested in purchasing them over the next two years. The regulator was soon forced to reconsider x values, when one of the RECs offered shareholders a significant pay-out in defending against an aggressive take-over bid. This was the first time that the value in the RECs had been publicised so blatantly, and the regulator responded by forcing the RECs to accept higher values of x, between 14–17%. Though the RECs protested publicly, the fact that all eventually accepted without resorting to the MMC demonstrated one of the weaknesses of this form of regulation in an immature environment.

Vertical integration had been pursued by the RECs by taking equity stakes in IPP developments. Generators also started such moves in 1996, when Scottish Power was allowed to take over Manweb (one of the RECs) without reference to the MMC. However, when the main England & Wales generators, first PowerGen and then National Power, attempted to buy the Midland and Southern RECs respectively, the government's Office of Fair Trading referred the deals to the MMC. Although the MMC recommended approval, the government subsequently blocked both take-overs.

Following regulatory pressure, in 1996 the RECs decided to sell NGC via public flotation. A condition from government was that subsequent industry ownership be restricted, and generators and others had to sell off any share holding. Restrictions were also placed on foreign ownership of NGC. In the regulatory transmission review, the regulator initially requested that NGC accept x at 27%, but eventually agreed to 20%.

Also in 1996, the government restructured its nuclear assets into two companies, in order to sell off the newer AGR and PWR nuclear power stations as a single company, British Energy, with a realisation of around US\$3 billion. The older Magnox nuclear stations with their decommissioning liabilities were retained in government ownership.

Formal limits on cross-ownership disappeared in 1996, to be subsumed in the individual consideration given to proposed deals by the Office of Fair Trading, with possible reference to the MMC. The two main generators tried but failed to negotiate deals combining the take-over of RECs with the divestment of generation. However, under pressure once again from the regulator now that the price cap period had expired, they agreed to sell or long-term lease 4 GWe of generating plant to Eastern Electricity. Eastern, one of the largest RECs, which already had interests in new CCGT IPPs, thus became the first recognisable integrated utility in England & Wales, with significant fossil generation.

The opposition Labour Party, which had opposed electricity privatisation in the 1980s, began in 1996 to publicise its intention if it came into government to recover more value from companies which it considered had been privatised too cheaply. The boom in equity values during the 1990s, in particular in privatisation stocks, had caused capitalisation values to soar to levels two or three times the value at privatisation. The sectors under consideration were mainly electricity, gas and water, though all sectors were possibilities.

The Labour Party came into office following a general election in 1997. Within a few months it launched a review of fuel sources for power generation. This was prompted by the decline in the coal industry due to gas becoming the fuel of choice for new power stations. The new government also announced its intention to review the electricity trading arrangements, on the grounds that these were biased against coal. The expected one-off "windfall tax" on privatised utilities which had been signalled before the election was also introduced into proposed legislation.

In addition, the government announced its intention to review regulatory powers and methods across all privatised essential service sectors, indicating its belief that the existing powers were not sufficient to uphold the interests of customers.

The fuel sources review led to a moratorium on consents for new gas-fired power stations, pending the introduction of new electricity trading arrangements. The review of electricity trading arrangements concluded that the pool should be abolished in favour of bilateral contracts and a balancing mechanism. These arrangements were due to be introduced in October 2000.

In 1998, the government approved a windfall tax on the electricity industry totalling about US\$3 billion. The government also implemented its policy to stop gas plant construction. However, planning consents were to be considered on an individual basis, with combined heat and power schemes having some success with applications.

Meanwhile, the introduction of full retail competition to domestic and small business customers, which had been expected to begin on 1 April 1998, had to be delayed. The pool systems were ready and tested, but the developments required within the RECs' distribution and supply businesses to accommodate full competition took longer than planned. The industry was also mindful, after the problems of 1994, of the potential disaster that could arise from the unprepared and untested introduction of systems serving 23 million customers. Introduction was delayed until October 1998 and phased over the following six months as the systems of individual RECs were proved. Supply price controls were introduced for two years to allow the regulator to judge the degree of competition that emerged.

During 1998, enormous industry effort (involving hundreds of staff) became tied up in numerous consultation processes led by the government and the new electricity regulator. The latter was determined to gain powers to change the market to the advantage of customers.

By 1999 full retail liberalisation was complete, with all customers being able to change their supplier. The cost of this last phase of liberalisation was at least US\$2 billion, 75% of which was incurred by distribution businesses directly and was an allowable regulated cost passed through to customers. The rest was a cost on the supply companies competing at that time. RECs that were late in meeting timescales agreed with the regulator were penalised financially. The development took over four years for design and delivery, using typically an extra 200 experienced staff.

The initial design for full liberalisation, which was proposed by the pool, imagined a more significant role for the pool using a larger central system, with less devolved to the individual distribution and supply companies. Estimated costs for this proposal were around US\$400 million. This was rejected by the regulator as being too expensive, but the motivation was really to reduce the central role of the pool and to capture more power within the regulatory function. Eventually, this evolved into a motivation to replace the pool with an alternative market with a more central role for the regulator.

The hundreds of staff involved continued their efforts in the development of the New Electricity Trading Arrangements (NETA), which the regulator intended to implement in October 2000. The powers to introduce the new market and for the regulator to have unilateral powers to modify it were provided by the Utilities Act early in 2000. The total cost of introducing NETA was expected to be well over US\$1 billion, with no specific method of recovery of costs allowed for, other than through competitive pricing.

As October 2000 approached, it was clear that technical difficulties had delayed the NETA introduction. To remedy these and to allow adequate testing time necessitated a further delay. Because of the further delay, the government also lifted the moratorium on gas-fired plant construction.

Over the two years 1998–2000, vertical integration of the industry continued at a rapid pace. In addition to the emergence of the integrated companies Scottish Power and Eastern Electricity (now called TXU), the following integrations have occurred:

- The state-owned utility Electricité de France bought London Electricity, and the supply business of South West Electricity.
- PowerGen bought East Midlands Electricity.
- National Power bought the supply business of Midlands Electricity.
- Southern Electricity merged with Scottish Hydro.
- British Energy bought the supply business of South Wales Electricity.

The risk of not being vertically integrated were demonstrated in autumn 2000 when the largest independent supplier was declared insolvent. Credit cover within the Pool to pay generators for its purchases was totally inadequate and debts remain.

Current Objectives

The Labour government took office in 1997 with an enormous agenda of proposed change. During the first year it addressed the funding to resource its programme. From 1998 onwards the policy of safeguarding customers interests was expressed almost daily in the press regarding one sector or other.

One popular theme was consumer price comparisons between the UK and Europe or the USA for manufactured goods, in which prices were seen to be significantly higher in the UK and where transport charges should be relatively low. Some companies were shown to be fixing prices or preventing retailers from competing. In the financial services and insurance sectors, for example, high prices for simple low-cost services and restrictions on customer choice were continually highlighted. As a result, regulatory powers in the financial services sector were increased significantly.

This policy of increased regulatory authority over commerce reached the utilities sector, with the introduction of the new Utilities Act 2000. In the electricity sector, this Act provides the authority for the government and the regulator to introduce NETA and to increase regulatory powers. Previously, powers to change the electricity market lay with the pool members, with the required majorities defined in the Pooling and Settlement Agreement; the regulator had only a power of veto.

The role of RECs as both suppliers and as operators of the distribution network and metering systems has also caused concern because of the potential conflict of interest. New arrangements have been proposed to create greater separation.

The largest consumers of gas in England & Wales are the CCGT power stations. This has created a strong dependency between the traded gas and electricity markets, particularly at peak price conditions related to tightness in the supply of gas. The government has therefore decided to merge the gas and electricity regulators' offices, with associated changes to the consumer representation bodies.

Reasons for Reform in Electricity

Before the electricity market was introduced in 1990, there was criticism of how the industry operated, as discussed above. This was somewhat unfocussed and targeted generally at senior politicians and industry managers. However, subsequent reforms have fragmented the industry to produce many more targets for criticism.

In 1998, the regulator reviewed the electricity trading arrangements and reported the findings to the government. The report notes that: "In some respects (the arrangements) have worked well. The balancing arrangements have maintained the quality and security of supplies. The trading and pricing arrangements have assisted new generators in entering the market and have allowed competition in supply to be introduced."

However, the mission of the regulator was to remove the pool. Despite accepting that the pool was "cutting edge" when introduced in 1990, any praise in the report is limited to the single short paragraph above. To support the mission, the report's criticism is unbalanced and covers most of the essential features of the market, such as prices, market shares, new entry, market mechanisms, governance, and regulatory powers. The long list of criticisms of the pool in the review includes the following:

- The regulator cannot take steps directly to secure change in the pool.
- Bids into the pool by generators are not reflective of costs, and movements in pool prices have not matched reductions in costs.
- Since 1990, wholesale electricity prices have been largely unchanged, while the costs of generation in terms of fuel costs and capital and operating costs have reduced by almost 50%.
- Market power has been a factor in maintaining or increasing prices.
- The trading arrangements have facilitated the exercise of market power at the expense of customers by enabling all generators to receive a uniform price, which in practice has been set by just a few.
- It is possible that excess new entry has been encouraged at the expense of existing plant.
- New entry has been dominated by gas-fired plant, while the majority of closures have been of coal-fired plant.
- Electricity suppliers do not pay for electricity on the basis of negotiated prices, but at the single pool price, which inhibits supply-side price pressure.
- The involvement of the demand side within the pool is limited, leading to higher price spikes than would be the case with greater involvement.
- The complexity and opacity of the pool's price setting process and the lack of competition in price setting has inhibited the development of derivatives markets and reduced liquidity in the contracts market.
- Capacity payments do not provide a very effective short-term signal to generation and demand, since they do not accurately reflect short-term changes in capacity margin.
- Capacity payments have not worked as intended since in years when capacity payments have been low, generators have increased system marginal prices.
- Increasing interaction between gas and electricity markets will lead to inefficiencies if generators are not faced with the financial consequences of withdrawing scheduled output from the pool.
- Generators and suppliers do not face the costs and consequences of their actions because neither make firm commitments to generate or consume electricity.
- Pool governance arrangements are inflexible and have precluded change or delayed reform.
- There is no simple way to modify the pool's centrally planned price setting mechanism to achieve more competitive prices.
- Despite reduced market concentration in generation, pool prices are still capable of being manipulated.
- Experience elsewhere in the world where electricity liberalisation is taking place shows a trend towards market-based solutions.
- The trading arrangements in England & Wales are no longer at the "cutting edge", as they were when first introduced.

Observations

Government Influence

The 1990s saw vast changes in the electricity industry. It began the decade in government ownership and control, its fuel supply dominated by coal from a government-owned supplier, selling power profitably to all customers apart from

some very large industrial customers (which were subsidised). The Conservative government then sold almost all of the industry into the open market environment that it introduced. However, the government's policy of liberalised competition was regularly interrupted by its own short-term policies, and those of the regulator, regarding electricity industry structure and dependent industries.

Government control via the Department of Energy disappeared to make way for competition policed by the Office of Fair Trading and overseen by an industry regulator with light regulatory powers. Customers and shareholders both benefited. One of the main themes of the Conservative government was to encourage private investment, and in particular to encourage individuals to become shareholders. Though electricity prices were reduced, most of the benefits from efficiency gains within the privatised companies were received by the shareholders.

The new Labour government in 1997 introduced policy proposals with the aim of returning more value to customers through competition, accompanied by firmer control through regulation. Government interference still continued as before, with a large claw-back of cash from the industry and a moratorium on gas as a fuel for power generation. This was by now the dominant fuel, but jobs in the coal industry still commanded political support.

A cycle seems to have taken place. Under the Conservatives the industry moved away from government ownership and control, but it now appears to be moving under Labour back towards government control through a strengthened regulator.

Successes

The current reasons for further reform have been expressed above mainly from the consumer and Labour government viewpoints. However, a more balanced view of the last 10 years would include a review of the original objectives, as well as other viewpoints. It should also be recognised that England & Wales introduced novel features by breaking up the industry and introducing a pool market when there was no previous experience with which to assess the likely outcome. There have undoubtedly been some major successes, not least the downward trend in electricity prices, which was in contrast to that in Europe. England & Wales, and subsequently Scandinavia, have been able to demonstrate to other countries the advantages of liberalisation.

The following statements address the government's objectives in 1988, as quoted above:

1. Achieved. Power station investment decisions throughout the 1990s were driven by distribution companies, both through equity investments and PPAs.
2. Mainly achieved. Greater competition has produced downward pressure on prices, although customers have not come first.
3. Achieved. Customers have been given the rights expected, predominantly that of choice.
4. Achieved. Managements have had more freedom to use their initiative.
5. Achieved. The security and safety of supply have been maintained.
6. Achieved. Investment plans were open to commercial tests and financed privately.
7. Achieved. Employees and customers can and do own shares in the industry.

The objectives of the initial reforms have therefore been delivered in almost all respects. Considering that there was significant scepticism that private investment would be forthcoming, and about whether a market could deliver security of supply, what has been achieved is of a high standard. Having said that, political objectives are rarely of a quantifiable nature and most customer attention turned quickly to prices, forgetting other objectives (interestingly, prices had not been an issue when the industry was state owned). Pressure for further reform stemmed from this one aspect.

In the decade following liberalisation and the introduction of the pool there have been several benefits, including:

- Supply prices have been reduced.
- Competition in supply has been introduced, almost in line with the expected programme.
- Regulation has reduced prices in the remaining transmission and distribution monopolies.
- Standards of service to customers have improved.
- The government no longer has to finance the industry and has secured regular and substantial tax revenues from the privatised companies.
- Shareholders of the privatised companies have enjoyed good returns on their investment.

The key issue has been how the gains have been shared between customers and shareholders, which is captured by the relative successes of the first and last of the above points.

Under the Conservative government, shareholders had seen their investment grow by two to three times, which was characteristic of equity investment between 1990 and late 1998. Complaints from customers concerned the profitability of the industry, and the Labour government has addressed this imbalance. However, electricity share prices fell rapidly during 1999 with companies seeing reductions of 30–50% during the year, mainly due to increased regulatory risk.

Electricity prices since the introduction of the market have shown:

- a 30% reduction for large industry;
- a 25% reduction for commerce;
- a 25% reduction for households.

Prices in 1999 were typically around 2.2 p/kWh (3.6 US¢/kWh) for the largest industrial customers, around 4 p/kWh (6 US¢/kWh) for medium-sized companies taking 2.5 MWe at a 40% load factor, and around 8 p/kWh (12 US¢/kWh) for households. The annual value of total electricity sales in England & Wales was around US\$30 billion.

Failures

As mentioned above, the main criticisms from customers have concerned the gains received by shareholders in the privatised companies. These can be expressed in the following points:

- The valuation of assets at privatisation was too low, although the government was unsure of the investment appetite during the Gulf War. The Labour government has since addressed this.

- The profitability of the RECs was too high until 1995. The issue of distribution price control was reopened in March 1995, but was settled by increasing the valuation of assets by only 15%. This resulted in distribution companies not being effectively regulated until 1999 (for the period 2000 to 2005).
- The structure of the generation market, in terms of both assets and market share, combined with system marginal pricing in the pool, resulted in prices being too high. Total excess payments were £1.5 billion (US\$2.3 billion) according to the regulator, and £3 billion (US\$4.5 billion) according to others.

The pool market was designed to be a reasonable attempt at modelling the physical delivery of electricity from power stations to the different categories of customer, while providing incentives to perform and reflecting the allocation of costs appropriately. However, the physical system is always more complicated than the model, and the deficiencies observed by customers and the regulator became difficult to solve in a simple manner in an already complex model.

The irony of this is that several market models were considered in 1989. A key requirement was a software package to optimise generation scheduling according to the forecast for the day ahead. The CEGB used a program called GOAL for operational advice on planning and despatch. Although an excellent program in many respects, it was not auditable and was considered to be unsatisfactory for use in the new market. No other suitable package was found, and consequently new software was specified and commissioned. However, in mid 1989 it emerged that there was an insurmountable problem with the new software. Thus, shortly before the market was due to commence operation, the decision to use GOAL despite its shortcomings was taken.

Some early criticisms of the market and price setting were thus directed at GOAL. With no better software being available, many clever fixes had to be found to allow the market to continue. This persisted for the first three years and beyond.

In addition, one of the proposed market models was based upon the principle of isolating particular activities and giving an accurate incentive to perform each activity. Again the model was based upon the physical reality of how the existing system was despatched in short timescales. This model required the individual costs associated with differences between the day ahead forecast and the actual real-time operation to be charged to those that caused them. These would be allocated as follows:

- Costs of changes in generation availability would be charged to generators.
- Costs of differences between instructed generation level and out-turn would be charged to generators.
- Costs of changes caused by transmission constraints would be charged to the NGC.
- Costs of changes between forecast demand and actual demand would be charged to the NGC and the distributors.

Incentives identified would require differences between five optimised generation schedules to be determined. Unfortunately, this amount of calculation and settlement could not be done in one day of computing, given the size of the England & Wales system. Thus, the model was simplified towards the end of 1989 to use an unconstrained forecast schedule and actual metered output. This system was then prototyped over a three-month period, and become the basis for the price and payment mechanisms for the start of the pool in March 1990.

Over the following years, the regulator and customers requested that those responsible for the various costs listed above should be identified, despite the difficulty of this task. The pool was then criticised, often unfairly, for taking a long time to include these developments in the market.

Over time, most of the information complexity from the five optimised schedules has been developed, via either on-line or off-line methods. Because of the complexity, timescales for change were long, typically two to three years. For participants in a business involving large capital investment over periods of 40 years, this rate of change seemed reasonable. But not so to customers and the regulator, who were searching for changes which would reduce prices or allocate costs to the industry. Eventually the public relations battle between the regulator and the industry over pool development was won by the regulator. When NETA is introduced in March 2001, the regulator will have unilateral powers to change the market, though there are modification procedures to adhere to.

The governance of the market was then seen by customers and the regulator as the prime target for reform, which meant that the industry could no longer hold such influence over how it priced or marketed its wholesale energy.

Operational Costs

Apart from the specific major costs mentioned above, the ongoing annual costs of operating the market have typically been as follows:

- Pool development costs: US\$25 million, using 80 staff.
- Pool costs for production: US\$60 million, using 300 staff.
- Regulatory costs: US\$25 million, using 400 staff.

The regulatory budget, which has been growing rapidly, is recovered through licence fees. In 2000, the gas and electricity industry regulators were to be merged, with the combined budget rising by 30% compared with 1999, to US\$105 million.

Proposed Programme of Change

Although England & Wales has full retail competition, supply price controls will be maintained until 2002 so that the regulator can assess the degree of competition that has developed.

From March 2001, the design of the wholesale electricity market is due to change. The pool will be replaced by another market design prepared by the regulator and the Department of Trade and Industry (DTI), introduced under government legislation which transfers powers over the market from industry participants to the regulator. The high level design of the new electricity market is given in the following section.

On 1 March 2000, a new Competition Act took effect. This gave the Office of Fair Trading (OFT) and regulators sweeping new powers to fine companies up to 30% of turnover for price-fixing. However, the detailed rules were not in place in good time before the new provisions started to apply. UK competition lawyers have said that the regulations appear tougher than European Union rules, and will make it harder for UK companies to defend themselves.

The new Utilities Act is also designed to reform the operation and regulation of electricity, water, gas and telecommunications utilities. The Act makes protection of consumer interests the principal objective of regulators. This is aimed at

achieving what is considered by government to be a fairer balance between the interests of consumers and shareholders. Provisions include:

- Powers for the gas and electricity regulator to introduce new electricity trading arrangements.
- Regulators being able to impose unlimited fines on companies found guilty of bad practice or poor performance, including mis-selling and interruptions to supplies.
- Powers for the government to establish energy efficiency and renewable energy targets.
- The establishment of "one-stop" independent consumer councils to champion consumer concerns and to investigate complaints.
- Powers for the government to adjust charges if electricity companies treat disadvantaged customers unfairly.

The powers for regulators to impose unlimited fines on companies for bad practice go beyond those under the new Competition Act and under European Union legislation.

Criteria and Objectives for Market Design

The criteria for the design of the 1990 trading arrangements can be considered to be the delivery of the design objectives set out earlier, together with meeting the development programme agreed at the time.

The development programme was predominantly to phase in competition in supply as follows:

- By 1990: customers above 1 MWe (to date around 50% uptake).
- By 1994: customers above 100 kW (to date around 50% uptake).
- By 1998: all customers (achieved in March 1999, initial uptake less than 5%).

Other developments identified in 1990 when the market started operation, but needing to be implemented later, included:

- the replacement of the GOAL scheduler with auditable software by 1995;
- a market treatment for transmission constraints;
- a market treatment for the allocation of transmission losses;
- the testing of generation availability.

Under the constitution of the pool, it has to review its overall operation every three years. The first pool review was in 1993–94. By 1997, the pool was working flat out to implement full retail competition to all customers, but the new government had already announced that it would review market operation as part of its review of fuel sources. The pool therefore started a more fundamental review of itself in order to be able to assess alternative market structures against its original and new design objectives.

The original design objectives of the pool's trading arrangements from 1989–90 were:

- To ensure system security.
- To facilitate efficiency by encouraging efficient despatch, maintenance of generation capacity, investment and consumption.
- To smooth payments between periods.
- To minimise transaction costs.

- To provide transparency and stability, by minimising regulatory risk, achieving an acceptable balance of power in governance, protecting against discretionary acts or power, and discouraging gaming.
- To accommodate policy constraints, by providing a level playing field for new entrants, freedom of contract form, a single national price, and support for marketing off-peak electricity.

After debate, new design objectives were drawn up in 1998. The overall objective was that the trading arrangements should deliver the lowest possible sustainable prices to all customers, for a supply that is reliable in both the short run and the long run.

Subsidiary objectives for the trading arrangements were:

- They should facilitate efficiency in the generation, transmission, distribution, trading and consumption of electricity.
- They should minimise entry and exit barriers for generators and traders of electricity.
- They should support the need for system security.
- They should maximise market participants' freedom of choice, subject only to limitations justified by other objectives.
- They should provide transparency in the operation of the pricing mechanisms and of the market generally.
- They should minimise unnecessary and unmanageable commercial and regulatory risk, as should the process for changing the arrangements.
- They should minimise all related transaction costs, including those incurred by customers.
- They should be consistent with competition law and with other laws, but they should not be used as a vehicle for implementing policies extraneous to their scope, as defined by the other objectives.

In essence, there was a much greater emphasis in the revised objectives on customer needs: prices, quality and non-discrimination. Important related objectives were efficiency and competition, system security, and the stability and transparency of markets. Smoothing payments and risk control were regarded as less important, as confidence in markets and trading has grown.

However, the pool's own review process was overtaken by the government's announcement that it would be proposing new legislation to provide it with powers to change the market, and hence to be able to introduce NETA in 2000, though since delayed to 2001. The DTI and the regulator commenced designing and developing a new market. The pool members, and the industry as a whole, were then essentially only consulted as necessary on the forthcoming change.

Most of the detailed market proposals for March 2001 are available on the Ofgem (regulator) or Elexon (Market Operator) web-sites (www.ofgem.gov.uk and www.elexon.co.uk).

The general features proposed for the new market are:

The new electricity trading arrangements are designed to be more efficient and provide greater choice for the market participants whilst maintaining the operation of a secure and reliable electricity system. The proposals are based on bilateral trading between generators, suppliers, traders and customers. They include:

- *Forward and futures markets (including short-term power exchanges), which evolve in response to the requirements of participants, that will allow contracts for electricity to be struck over timescales ranging from several years ahead to on-the-day markets.*
- *A balancing mechanism in which NGC, as system operator, accepts offers of and bids for electricity to enable it to balance the system.*
- *A settlement process for charging participants whose contracted positions do not match their metered volumes of electricity, for the settlement of accepted balancing mechanism offers and bids, and for the recovery of the system operator's costs of balancing the system. There will be two balancing prices, a buy price and a sell price. The spread between these is important since a wide spread may encourage long-term contracting which is a desired feature, but also contract market liquidity is encourage by small spreads. Liquidity is also a desired feature of the contracts markets.*
- *Market governance will change from the industry majority decision making under the current Pool market to unilateral powers for the Regulator under NETA for the Balancing and Settlement market.*

APPENDIX 3. STUDY COORDINATOR'S OBSERVATIONS ON THE LIBERALISATION PLANS PRESENTED

The following are the Study Coordinator's own observations on the liberalisation plans presented by Steering Committee members in the course of this project. The discussion of these observations and conclusions with Steering Committee members was an important step in fulfilling the aims of the project. The comments build on the analysis presented in the main report and concentrate on those countries and areas that have more developed plans for liberalisation over the next few years. Comparisons with other markets and countries with similar issues are identified.

General observations which apply to most countries or areas are not repeated under each heading. The following issues are dealt with under the headings as shown in the table below:

Issue	Heading treated under
Asset value	Philippines, South Korea
Debt reduction	Philippines, South Korea
Generator competition	Philippines, South Korea
Governmental & regulatory powers	Australia, New Zealand, Philippines
Integration of the grid	Australia, China, Philippines
Market models	Philippines, South Korea
Private investment environment	China, Indonesia, Taiwan, China

1. Australia

1.1 Criteria for Further Development of the Market

The aims of the next phase of liberalisation in Australia can be summarised as:

- To achieve greater integration in the approach to electricity and gas industry reforms.
- To develop improved methods for facilitating interconnections between states, with a fair comparison with the alternative of new generation construction.
- To improve the operation of the electricity market in the light of Australian and overseas experience, especially in the areas of market design, ancillary services, handling of regional price differences and ensuring adequate reliability.
- To increase the generating capacity, and the competition in generation, in some states.

There is concern that the pool market design with no capacity incentives may deliver neither adequate competition nor capacity. The numbers of generators in each state is relatively small and the interconnections of relatively low capacity, thus fragmenting the market. An integrated wholesale energy market across the

south-eastern states, with benefits and costs shared fairly between states, must be the appropriate aim. It should not be influenced significantly by network interconnections that are either sub-optimal or unfairly charged.

Another specific concern has to be the industry structure within New South Wales (NSW) in terms of the size and ownership of some distribution and generation companies. Any dominance exhibited here will have a very central effect on the national market.

The requirements for the probable success of a competitive market for price setting in generation are given in the table below. The reason for the "Yes/No" answers is that the approach to liberalisation in the various states has varied. Victoria started liberalisation by introducing a generation pool with sufficient numbers of competitors with similar cost structures for aggressive competition. However, the subsequent joining with NSW and South Australia in the National Electricity Market has reduced competition for price setting, since this is now dominated by the two largest NSW generators.

Profile: Australia	Generation/ Supply	Yes or No
Does the market need lower consumer prices?		Yes
Does it have an attractive investment environment?		Yes
Does it have high prices?	Generation: Supply:	Yes/No Yes
Is there easy access to the grid/market place?	Generation: Supply:	Yes Yes/No
Is there excess capacity in generation?		Yes/No
Is the transmission grid system well interconnected?		No
Are there many competitors?	Generation: Supply:	Yes/No Yes/No
Have other market-specific requirements been satisfied?		No

Wholesale prices in the smaller states of Queensland and South Australia, where insufficient capacity and hence inadequate generation competition exists, have been very high and have led in turn to high retail prices. In the larger states of Victoria and NSW, competition in generation is better, but the structure in NSW, where all three generation companies remain government-owned, is a concern. Prices in these two states have been below replacement costs but have recently risen substantially, itself a common sign of inadequate competition.

States other than NSW are short of generation, so the natural development is to construct new plants in these states and to improve connection to increase transfers to the Northern Territory, where prices and growth are high, albeit the market is small. Problems arise because of differing regulations and controls in each state. New interconnections between NSW and Queensland are about to be commissioned which will increase competitive pressures in Queensland. Because interconnections between states have high commercial value, the negotiations and agreements to put these connections in place are proving troublesome. This must be resolved for the benefit of all.

The dominance of the NSW generators can be used for both commercial and political purposes. An interconnected market of south-eastern states will put NSW with its two large state-owned generators in the driving seat. Adequate competition in a national Australian market will only return if the NSW generators are split up. However, with these generators in government ownership, this lack of competition may not result in high prices. Government dominance of the market can result in prices being depressed, depending upon government policy. This is a concern for private investors.

1.2 Conclusions

A subjective comparison with international experience suggests the following conclusions.

Intensity of competition in the generation sector. There appears to be a lack of adequate competition in generation in all states apart from Victoria. This is partly attributable to the stalemate that has developed on further privatisation in states other than Victoria and South Australia.

There appears to be a need for more active monitoring of market performance in relation to market power issues and the need for a robust enforcement regime to deter gaming in the market.

Market design. The design of the electricity pool that was adopted in Australia is no longer state of the art, especially in the light of the decision for England & Wales to abandon its compulsory spot price pool system.

Network pricing and development. The form of network pricing regulation being used in Australia is still causing concern both to customers and investors. There are divided responsibilities for dealing with system losses and transmission constraints.

A stalemate has developed in the rules governing the development of new interconnections between the states. This is of particular concern given that the encouragement of stronger interconnections was a priority objective when the national market was first suggested in 1991.

Continuance of government involvement. The extent of continuing involvement of governments in the industry is a concern not only in relation to their trading entities but also in relation to their ownership of NEMMCO and NECA. This concern arises from the conflict between state government revenue requirements and the inevitable effect of competition that reduces electricity prices and hence state revenues.

The governance arrangements do not provide for customer representation on NEMMCO and NECA. These organisations have been criticised for their high operating costs.

Excessive regulation. There is a complex proliferation of state and federal regulatory agencies in Australia, with excessively complex rules, high regulatory costs and the risk of inconsistent decisions.

Conflict with environmental policy. There is an obvious tension between environmental policy and energy policy. Competition and low electricity prices are holding back the commercial development of non greenhouse gas emitting generation technologies, and actually increasing the contribution of greenhouse gas intensive coal-fired power.

2. China

2.1 Criteria for Market Design

Stable Investment Environment

In view of the large demand growth in China and the investment needed to construct about 200 GWe of new capacity over the next 10 years, one of the key objectives is a stable investment environment with reasonably predictable generation volumes, prices and rates of return. Predictable and efficient application approvals, contract management, regulatory and legal frameworks are also required.

To gain value for money in the investment stage, construction tenders should be evaluated locally using electricity prices based on long-term costs. However, short-term merit order despatch should be based on short-run costs, including contractual flexibility and reward, since it costs more to provide flexible output. Current project contracts are inflexible, being founded on baseload operation.

The objectives are:

- To develop a business environment that attracts investment in 20 GWe per annum of new generation capacity, using contracts that encourage flexible output to enable daily demand variations to be despatched.
- To determine and construct the appropriate national transmission system that is consistent with minimising overall generation and transmission costs, while meeting the demand growth.

Restructuring

There are several aspects to the restructuring proposals which are very positive and support other objectives. The broad proposal is to separate generation from transmission. Together with more local responsibility it permits:

- local decisions on generation construction needs;
- local despatch and operation of generation markets;
- overall economic despatch of transfers between regions.

Electricity losses in transmission normally make the transfer of power over more than 1000 km uneconomic, unless for emergency or strategic reasons. A reasonable size of load to despatch within local grids is around 200–300 TWh. It would be reasonable to adopt a common policy across China to manage the optimisation of transfers between these individual regions. Although it is not necessary to adopt a common approach to transfer charges and to losses, it would assist local decision-making if consistent policies were used for inter-regional transfers.

The criteria is that clear responsibilities are agreed by local management for distribution and generation, and by national management for standards, the regulatory and legal framework, and for management of inter-regional power transfers.

Market Structure

Several market models are being investigated for generation competition, but with the state-owned local distribution companies acting as single buyers. Competitive

despatch and price setting can be tested while continuing to use contractual terms for financial accounting.

Issues for consideration in interactive markets and transfers are what prices to use within neighbouring regions, and what prices should local purchasers pay. These features are considered more generally in the generic chapters since the allocation of benefits and costs is an issue for interconnection trades in general.

2.2 Conclusions

A summary of the objectives to be met in the next phase of liberalisation is:

- To develop an investment environment that attracts 20 GWe of new generation capacity annually, and allows flexible despatch of plant.
- To produce a clear division of responsibilities between regional and national markets.
- To develop simple regional markets that allow fair trading between regions, and the optimisation of power transfers.

The requirements for the probable success of a competitive market for price setting in generation are given in the table below.

Profile: China	Generation/ Supply	Yes or No
Does the market need lower consumer prices?		Yes
Does it have an attractive investment environment?		No
Does it have high prices?	Generation: Supply:	Yes No
Is there easy access to the grid/market place?	Generation: Supply:	No No
Is there excess capacity in generation?		No
Is the transmission grid system well interconnected?		No
Are there many competitors?	Generation: Supply:	No No
Have other market-specific requirements been satisfied?		No

The issues in China are the construction of sufficient capacity in generation, and the interconnections between provinces so that large hydro schemes are able to transmit their power to larger demand areas. The investment environment is not as attractive as some other countries because of bureaucracy and difficulties in resolving disputes.

Competition is needed in the operation of part-loaded generation to meet the load shape. An investigation of market models will give some insights, but the part-loading despatch of plant can use long-term cost information known to system operators without the need for short-term bidding for price or despatch. Regulated solutions are required for the foreseeable future. Competition is required only in the construction sectors, to ensure reasonable prices are offered to the provincial purchasing authorities.

The clear observation is that within individual provinces there is no excess capacity and too few competitors for competitive price bidding for a market price. Seasonal cost information bid into the system operator will provide for the despatch of part-loaded generation.

3. Hong Kong, China

3.1 Criteria for Market Design

The electricity industry in Hong Kong is typified by robust reliable supplies from both of the private utilities under an agreement with the government which lasts until 2008. The objectives for the future should include:

- To decide, sufficiently early for implementation, the way forward post 2008.
- To appraise in advance of 2008 possible future industry structures embracing competition or regulation, given the current structure of two private vertically integrated utilities.
- To decide if the current structure of the industry should be broadened to include a wider regional model which includes the significant connection to the neighbouring province of China.

3.2 Conclusions

The requirements for the probable success of a competitive market for price setting in generation are given in the table below.

Profile: Hong Kong, China	Generation/ Supply	Yes or No
Does the market need lower consumer prices?		Yes
Does it have an attractive investment environment?		Yes
Does it have high prices?	Generation: Supply:	Yes Yes
Is there easy access to the grid/market place?	Generation: Supply:	No No
Is there excess capacity in generation?		Yes
Is the transmission grid system well interconnected?		Yes
Are there many competitors?	Generation: Supply:	No No
Have other market-specific requirements been satisfied?		Yes

The key factors to consider are that there are only two vertically integrated utilities, which have regulated agreements in place until 2008. The utilities have sole responsibility within their own geographic regions and despatch their own plant. Although the excess capacity and transmission systems are positive factors, the introduction of competition in generation to set prices or to operate will not be successful with this structure and would be a waste of investment and resources. However, both companies may benefit from mutual optimisation of their despatch costs leading to beneficial transfers, and this could be managed within regulation.

The way forward is to negotiate a regulated agreement that includes prices with which the government and public are comfortable. Failure to achieve this would encourage a restructuring of the industry and the introduction of competition. This would have high implementation costs. The government and the two companies should be able to calculate these, together with the likely outcome of competition. This should enable both sides to settle for a regulated compromise.

4. Indonesia

4.1 Criteria for Market Design

Features of the electricity industry in Indonesia include high debts from power purchases at prices that exceed the prices charged to customers, and a large over-capacity of generation in the Java-Bali system.

The urgent short-term objective is therefore to develop a plan to reduce the outstanding debts and to decide how to repay them through electricity charges. This may include re-negotiation of contracts and termination payments. Generation contract and despatch costs in Java-Bali need to be minimised.

Following on from the above, and to repair relations between investors and government, the objectives are:

- To re-create a stable and attractive environment for investment.
- To develop a legal and regulatory framework.
- To continue infrastructure development.

When new generation is eventually needed the criteria will be that prices charged exceed the costs of the new entrant generation.

With significant infrastructure investment required to connect island communities, subsidies from the Java-Bali area to other areas are likely to continue. Apart from competitive tender appraisal to improve value-for-money in investment, proposals for further liberalisation would be premature.

4.2 Conclusions

The requirements for the probable success of a competitive market for price setting in generation are given in the table below.

The 1997 fall in the currency exchange rate with the US dollar, which is used to price IPP power contracts, had the effect of leaving domestic end-user prices below the level of contract prices, thus increasing debt. The effect of the devaluation on industrial and manufacturing output was to reduce electricity demand growth, so that in the Java-Bali system there was an excess of plant being constructed. Elsewhere the need for construction in generation and transmission continues.

The requirement is to manage the excess capacity and its operation in Java-Bali. Generation prices are determined by contractual terms. However, operation must be despatched using some price or cost information. For the benefit of Indonesia this should be done with the objective of minimising overall contract payments to independent generators and the costs of utility owned generation.

Competition could help in this respect but there seems no need to create short-term prices at this stage. This is more worthwhile when there is competition to buy from competing suppliers. Competition for operation of generating plants can

be achieved economically by the use of suitable scheduling software, using generator costs that vary only seasonally. This would not require a large investment in pool-type arrangements. The input costs would need to be audited for suitability and accuracy.

Profile: Indonesia	Generation/ Supply	Yes or No
Does the market need lower consumer prices?		No
Does it have an attractive investment environment?		No
Does it have high prices?	Generation: Supply:	Yes No
Is there easy access to the grid/market place?	Generation: Supply:	No No
Is there excess capacity in generation?		Yes
Is the transmission grid system well interconnected?		No
Are there many competitors?	Generation: Supply:	No No
Have other market-specific requirements been satisfied?		No

5. New Zealand

Having liberalised the market in New Zealand the issue is what to do next. Are the government, the electricity industry and customers satisfied with the current market? In this respect the customers and the government may consider that customers should benefit more, rather than shareholders.

Objectives for the near-term should include:

- To decide if benefits to customers should be delivered through generator privatisation values, or more competitive prices.
- To achieve reductions in prices and charges.
- To achieve a balance between benefits to shareholders and customer savings.
- To decide whether a regulator is required.

The requirements for the probable success of a competitive market for price setting in generation are given in the table below.

An interesting observation regarding this liberalised and lightly regulated market is that since the introduction of a pool, prices to retail customers have seen no significant reductions and less than 2% of customers have switched suppliers. Wholesale generation prices have seen reductions with the restructuring of generation into competing companies. However, until the latest restructuring in 1999 the reductions were not significant. The reluctance to change suppliers is either because it is too difficult or because the effort is not worth the savings that arise.

New Zealand has prices dominated by hydro generation and hence has relatively low prices when compared internationally. In addition, the light regulation arises because there is no regulator, and this has played into the hands of supply companies, which are able to maintain their rates of return.

A conclusion is that light regulation needs a regulator. In addition, the complex zonal nature of the wholesale market is suppressing trading liquidity and hence competition.

Profile: New Zealand	Generation/ Supply	Yes or No
Does the market need lower consumer prices?		Yes
Does it have an attractive investment environment?		Yes
Does it have high prices?	Generation: Supply:	No Yes
Is there easy access to the grid/market place?	Generation: Supply:	Yes Yes
Is there excess capacity in generation?		Yes
Is the transmission grid system well interconnected?		No
Are there many competitors?	Generation: Supply:	No Yes
Have other market-specific requirements been satisfied?		No

6. Philippines

6.1 Criteria for Market Design

The Philippines has several short-term objectives that are being pursued. All are reasonable in their own right, but some are inconsistent with each other and some may be premature. The government has been considering industry change for about five years, so most debates are not new. Majority support for the way forward is the current requirement. The key objectives are:

- To interconnect additional islands.
- To continue to encourage private investment.
- To restructure the electricity industry.
- To maximise the privatisation value of the state-owned industry.
- To introduce a competitive power pool.
- To maximise natural gas utilisation, including that coming on stream.

To Encourage Private Investment

The Philippines has been very successful in attracting investment into the generation sector. There is now a large over-capacity, so that the issue is the price of generation and not the ability to supply. The driver for the government remains the reduction of industry debts and ongoing commitments. Realising high valuations from privatisation to reinvest in infrastructure is a key element here. The government has committed to connect the remaining 35% of villages and communities to main transmission services in the next 10 years.

The investment environment in the 1990s was seen as stable for IPP investment. However, proposed legislation to restructure the industry and to introduce a market is introducing significant risk in generation, both through market forces and regulatory risk. The proposed legislation would give increased powers to the government and the regulator compared with legislation seen in Australia and in

previous proposals in Brazil. While permitting the introduction of a market, the government would retain responsibility for satisfactory construction of generation, transmission and distribution facilities. In addition, the regulator would have largely unlimited powers to change market conditions. Recent proposals indicate that profits considered excess will be clawed back.

It may be, therefore, that the investment community will review the outlook on investment in electricity in the Philippines. This would be a disadvantage, as considerable investment is still required in distribution infrastructure. The introduction of too much market and regulatory risk may be premature.

To Restructure the Electricity Industry

This is a positive move that has shown benefits in reducing costs and improving efficiency and focus in many other markets. The issue is how to restructure. The obvious move is to split the National Power Corporation (NPC) into transmission and generation companies. However, with there being three main island groups, which are very weakly electrically connected, there is the alternative of restructuring within these three groups, or of phasing it differently over time.

With demand on the largest island group being only 30 TWh, and around 6 TWh on the others, the construction of a single additional large power station would have an enormous impact on any competitive generation market, to the extent that if it were contracted to operate then several smaller stations would not operate and should be closed.

In transmission, the large number of sparse communities and the very low per capita consumption means that unbundled transmission charges must either include significant cross-subsidies, or new infrastructure must be funded separately until increased local wealth has been created to pay the appropriate share of charges.

Transmission. The current proposal is for a partial privatisation of the new National Transmission Company, with the state retaining control. This would give the opportunity of bringing in a new strategic foreign partner to concentrate on the infrastructure and reliability, and hence to improve efficiency. In principle this privatisation should deliver a high asset value. A cautionary note would be that with continued state control, which is only natural for a strategic asset, the efficiency improvements may be considerably reduced. However, full privatisation is not consistent with the current policy of retaining government powers within the industry. Government concern should be to improve reliability and infrastructure construction. If government could hand over responsibility for efficiency improvements and cost reductions within the existing business then most of the value may be realised in the sale.

Generation. The position for privatisation of generating assets is far more complex and has considerable risk for investors. There are clear proposals to restructure 70% of non-strategic (pollution-emitting fossil, etc.) NPC generation into five portfolio companies and to privatise them. In principle this would hand over to new owners the task of operating these stations efficiently, since at present the large over-capacity results in NPC plant operating at low load factors, because of contracts with IPPs, which operate at considerably higher outputs. Reducing costs at the NPC plants would result in significant closures in the short term. In time, as new capacity is required, the sites could be used to re-build or the existing

plants could be converted to gas firing. These options would need to be supported by the forecast market prices in whatever form of market is implemented.

The potential impact of new station construction clearly imposes serious risks to existing stations that are not fully contracted, which are predominantly the state assets of NPC which the government wishes to sell to reduce its debts. The other key factor is that the Philippines has large gas reserves 500 km away, that if used for electricity generation or for exports would have a large impact on the economy. It would make sense to introduce this sooner rather than later. However, under the proposed competitive market for generator despatch, competition between new entry gas plant and the written down assets of existing fossil plant can only result in low wholesale energy prices in future.

The likely outcome is very low values being allocated by investors to the NPC stations to be privatised and less opportunity for the government to reduce existing debt within the NPC.

To Maximise Privatisation Value

This is a declared government objective. In the case of the partial privatisation of the transmission company, a successful outcome with a full price should be expected.

In the case of the generation assets, it is likely that their value is diminishing with time because of over-capacity, the use of indigenous gas in new stations, and because of the proposal to introduce a market based on competitive bidding to operate. The value of the generation companies lies in their forecast output rather than their capacity. It could be said that the proposed merit order bidding is the only way for some plant to run and have any value. However, privatisation yields would be higher if there was more certainty. Reducing the capacity for sale to levels consistent with expected operation and with contracted output for a number of years would almost certainly increase the total realised value by a significant factor. Another option may be to request tenders for specific generating stations, thus spreading ownership and increasing the number of future competitors.

This objective is not deliverable except in the sense of taking account of the impact of the other key objectives on the asset values.

To Introduce a Competitive Power Pool

Market design proposals have been under consideration for two or three years, and these have focussed on a generation bidding pool for competitive despatch and price setting. Customers and wholesalers above some threshold, probably 1 MWe, would be able to purchase directly from the pool or from supply companies (generators and distributors).

The key question to be considered here is, what is the purpose of the market? A power pool can deliver several important features such as:

- A market outlet for non-contracted generation on a level playing field basis.
- The ability for new CCGTs to enter the market if they can under-bid existing plant.
- A market of last resort between unwilling buyers and unwilling sellers.
- A merit order for competitive despatch.

However, the legislative debate has indicated that the purpose is to introduce competition and competitive price setting. These require certain circumstances to exist if they are to be delivered through a system marginal price pool. The key requirements include:

- A well-interconnected transmission system.
- Over-capacity of generation, where the excess is much greater than the largest generator.
- No large portfolio generators (greater than 10% of demand).
- New entrant prices must be lower than existing marginal costs.

Competition between generators will only occur to the extent that interconnections between island groups will allow it. With relatively weak interconnections, the market will be effectively divided into three, unless transmission constraints are ignored. This would cause inefficiencies, but since market designs are artificial anyway once many rules and restrictions are imposed, this may be acceptable in the early stages of the market.

The largest market zone is Luzon, with two proposed portfolio generating companies and some smaller IPP projects. There would be too few competing companies to produce competitive market prices for wholesale energy. With this small number of generators in private ownership, with obligations to deliver shareholder profits, prices in the market would be expected to remain high. So the market would not deliver competitive prices, but it might allow new gas plant to enter over time. This may be why powers for the regulator to claw back excess profits have recently been included in the proposed legislation.

Because the pool-type design of market will not deliver competitive prices, and because pools are expensive to implement and operate, it may be simpler to introduce a contracting market based on bilateral agreements. It is doubtful that the objective of the government is to introduce a complicated pool, whose price would be maintained above competitive costs, just to achieve higher values for the privatisation of generation assets. It is more likely that the number of portfolio companies was set at five for practical reasons, as some analysts believe this is the minimum number of companies to produce competition. In markets with a variety of production costs, the required number is much larger. Therefore it would be unwise to initiate a market with this proposed structure.

The lack of potential competition should be recognised and either a simpler market employed or regulated tariffs should be set by the regulator. These could be based on seasonal costs of production for the competitive merit order. Plant not needed could be closed or mothballed until later.

Another aspect is that there is little point in producing intra-day price variations unless there is significant demand that can respond to this price variation. One would not expect that to be the case here.

To Maximise Natural Gas Utilisation

A political objective of the government is to promote the use of indigenous fuel for electricity production. The government also wishes to control the operation of geothermal generation, which will not be privatised.

Western Europe has shown the enormous benefit that significant gas production can bring in terms of balance of payments and reducing internal energy costs. Because of the current over-capacity in generation this fuel will not be introduced

as quickly as it might have been. However, a stable market based on long-term merit order costs may allow gas stations to replace existing high cost fossil fuel stations. The government should consider the benefits that gas would bring, together with the impact of the form of the market, and the combined effect on privatisation sales. The overall benefit to the country is not obvious in the current restructuring and market proposals.

6.2 Comparison with International Experience

To Encourage Private Investment

This is an area of success, which needs to be extended to transmission and distribution infrastructure. The tendency worldwide at present is to increase the powers of regulators and this will have an impact on investment, but more probably on the value of a project rather than on the willingness to invest.

To Restructure the Electricity Industry

Restructuring into several generation companies will require new central management functions to be created. Although restructuring will allow individual costs and charges to be separated, efficiency gains in generation will only come about through competition and delivering shareholder value. In transmission, increased efficiency will come about through the expertise of the regulator and delivering shareholder value.

Both sectors require privatisation to introduce the drive for increased value for shareholders, to deliver efficiency gains.

To Maximise Privatisation Value

This is the objective that should be dropped. Maximisation usually requires price rises and long-term contracts. The outcome is the delay of competition and therefore continued higher prices. The Philippines is not considering raising prices to increase the asset values and a proposal to introduce competition into the merit order for operational running would be negated if the NPC generation were contracted for 5–10 years. There are several examples of this in relation to pools (e.g. England & Wales, Spain, California).

The government needs to decide between value realised and the introduction of competition. The earlier that competition is introduced the lower the asset prices and the less the ability to repay debts. If debt reduction or raising cash is more important than competitive energy prices then the government should decide on future energy prices and regulate them.

To Introduce a Competitive Power Pool

If merit order despatch is required to introduce competition in generation output, then it can be introduced much more cost effectively than through an England & Wales type pool. In England & Wales there are far more competitive generating companies than in the Philippines, and the common view is that competitive prices have not been delivered (although price reductions of 30% over 10 years have resulted). The points that are made in the section on the Republic of Korea also apply here.

To Maximise Natural Gas Utilisation

The use of gas as a fuel in CCGTs has had a significant impact in some markets, particularly in Western Europe where the costs of new entrant gas plants are considerably below those of coal-fired production. The potential use and development of the indigenous gas industry in the Philippines must be investigated to ensure that the form of the electricity market and the privatisation terms do not disadvantage a larger opportunity. The relative economics and timescales need debate.

6.3 Impact of the Proposals

NPC generation. It is quite clear that several of the existing marginal stations will have to close. Market prices will only support an excess capacity over demand of around 20%. With an existing excess approaching 80%, even though there are significant transmission constraints, there will be severe manpower reductions. If these sites are re-used for gas-fired generation in future, the manning levels will be very small compared with those of coal stations.

Downward pressure on capacity will arise from whatever competitive market design is implemented for generation. Encouragement of gas usage, even just for emissions reductions, will result in the same outcome.

Rural electrification. The significant amount of work still to be done to connect the remaining 35% of communities to a grid system means that subsidies and a requirement for significant funding will continue. The funding must be raised from somewhere, and end-users must pay for this somehow. If subsidies from Luzon to the other island groups, and from commercial to residential customers, were removed they would only need to be replaced by an alternative. The removal of subsidies is more urgent when a sector is to be introduced to competition and a "level playing field" is required to encourage new competitors.

Introduction of competition. In the case of generation, the number of competitors is too few to deliver competitive prices. In the case of distribution and supply a similar position exists, with a very dominant supply company in Luzon. There are therefore limitations on what can be achieved with this industry structure. What is more, the size of the market is probably too small for sufficient numbers of competitors of viable size. The infrastructure is relatively weak, which is another characteristic indicating that the industry is not ready for market competition in operational functions.

6.4 Conclusions

In summary, the key objectives for the Philippines are:

- To decide which is the higher priority, privatisation value or competition.
- To produce a plan to reduce debts and to fund infrastructure construction, including maximising privatisation values.
- To introduce a simple regulated market for plant despatch and wholesale energy.
- To encourage low cost indigenous fuels (gas, geothermal).
- To continue subsidies levied from different customer sectors.

The requirements for the probable success of a competitive market for price setting in generation are given in the table below.

Power system. The power system is effectively divided into three main transmission regions. The interconnections between them are not of sufficient capacity to be able to provide competition between these regions. Hence the market is fragmented and economic principles would suggest that the result is either three markets or three price zones. Privatisation proposals essentially create portfolio generators, with two in the largest region and one each in the other two regions. In the largest region (Luzon), there are some small independent generators and a large distribution company. Because of the excess capacity this distribution company will have market power in purchasing. There are therefore monopoly generators in some regions, and too few to create competition in another.

Profile: The Philippines	Generation/ Supply	Yes or No
Does the market need lower consumer prices?		No
Does it have an attractive investment environment?		Yes
Does it have high prices?	Generation: Supply:	Yes Yes
Is there easy access to the grid/market place?	Generation: Supply:	Yes No
Is there excess capacity in generation?		Yes
Is the transmission grid system well interconnected?		No
Are there many competitors?	Generation: Supply:	No No
Have other market-specific requirements been satisfied?		Yes

Market design. The Philippines is insufficiently connected electrically, and privatisation proposals will create too few competing generators, to allow a pool to produce competitive wholesale electricity prices. The alternative of creating more generating companies would be impractical since there would need to be over five in each region, and this would cause the smallest companies to risk very low operation levels and hence they may not be viable. Their sale could be problematic.

In terms of price setting, a pool would not produce competitive prices with this structure. A simpler market using regulated or audited costs for economic despatch would be simple and effective. If a market price is needed then seasonal or monthly prices could be produced from these costs. This would remove the issue of market power which exists with bidding into a pool, and would avoid large implementation costs. It is doubtful if any significant level of customer demand could respond to more frequent price movements.

A possible market that would be suitable would include the principles of a pool but would lengthen the time period for refreshing price input to monthly, possibly with separate day and night prices and weekday and weekend prices at a later stage.

If the priority is to produce truly competitive prices then a system marginal priced pool should not be adopted. If this is not the main purpose then a simple form of

market with regulated prices would be the least complex to use, and the improved stability could enable the government to realise higher value in the NPC privatisations.

Maximising privatisation value. This objective is inconsistent with that of achieving competitive prices if pursued at the same time. However, objectives such as reducing debts and the government's future funding commitment for infrastructure construction are very important. Therefore the optimum strategy would be to pursue maximum privatisation value first, and once this is done to try to achieve prices which are as competitive as possible.

Privatisation of state generation assets will not cover the debts within the industry. Consequently the government will need to raise additional income, probably through levies on the price of electricity. The funding must come from customers through some route. This will also fund rural electrification and grid reinforcement. Levies could be higher on certain customer sectors (e.g. the commercial sector, and in the Luzon region). The government may thus wish to see low wholesale prices and charges from privately owned generators, to allow the government to then raise prices through these levies. This latter route seems to be the direction that the government is moving, in which case the removal of subsidies would seem to be premature.

Since low energy prices and low transmission revenues for the privatised companies is the probable government strategy, and because the industry structure is not suited to strong competition for their delivery, it would seem appropriate for a simple form of regulated market to be introduced. That proposed is too complex and it is premature.

7. Republic of Korea

7.1 Criteria for Market Design

The short-term objectives can be summarised as:

- To maximise the value of privatisation assets.
- To manage the present generation over-capacity efficiently.

In the longer term, the objectives are:

- To ensure a long-term reliable and inexpensive supply of electricity.
- To eliminate cross-subsidies resulting in distortions in pricing.
- To improve customer satisfaction with services.
- To create a distribution and supply structure to deliver inexpensive electricity.

The second category of objectives can be delivered in several ways, mainly independently from the first. For example, competition for generation construction and competition for generation despatch will deliver efficiency, without requiring any market price setting from these activities. This is a worthwhile objective to follow.

The first objective depends directly on the electricity market price as far as generation assets are concerned. It is interesting to note that the objective of lowest possible energy prices has not been included, except in the diluted form of the third objective above.

It is possible that the government considers that it may be able to achieve maximum asset values from the privatisation of generating assets, and then

introduce a very competitive energy market to deliver lowest possible prices. However, this is difficult to sell to investors and often the result is a diluted objective such as the third one above. Such tactics by governments have been seen previously in other markets and investors value assets expecting this risk. However, the market structure and proposals are not those expected to deliver lowest prices, so it can be concluded that this is not the government's tactic, unless it holds different expectations of the market's performance.

Korea has most of the requirements for a very competitive generation market and the country may benefit more overall from having "lowest energy prices" as the prime objective, and then privatising generation accordingly to realise as much value as possible.

The above is supported by the following features:

- The transmission system is well connected.
- There is over-capacity that can be reduced through despatch competition.
- Competition will remove some coal generation to assist environmental targets.
- Manufacturing industry presently enjoys subsidised low electricity prices (the commercial sector cross-subsidises other sectors) and would be disadvantaged internationally if prices were raised to deliver higher rates of return for generators.
- The government only owns 51% of the Korea Electric Power Corporation (KEPCO), and the 12 GWe of nuclear plant is not due for privatisation. Therefore debt reduction through privatisation is in any case limited and would probably be reduced little by driving towards lowest energy prices.
- The government may avoid the apparent requirement to raise prices before privatisation and before market introduction.

The last three of the objectives above could be addressed by restructuring the industry into separate businesses with an appropriate benchmarking of performance within the method of regulation.

Competition

Generation. The proposal to introduce a generation pool is supported by the well-connected transmission system, the over-capacity in generation and the restructuring of generation into five similar competing companies together with a much larger government-owned nuclear company.

Since all existing generation pools have followed the England & Wales model of using a system marginal price to determine market price, and market models have been quoted as requiring at least five competing companies, the above proposal may seem reasonable. However:

- For a production cost curve ranging from hydro and nuclear to gas and coal, it would be possible to demonstrate that the five non-nuclear companies would quickly find a strategy of supporting prices in a system marginal price market. This is because they are sufficiently large to improve their income by reducing their available capacity and raising the prices of some of their marginal plant. To prevent this strategy succeeding would require the companies to be smaller than 10% of total demand.
- Even the nuclear company would benefit by reducing its declared availability to allow marginal plant from other companies to generate and set a higher price.

- A bidding pool as proposed is expensive to set up and development costs supposed to improve incentives and efficiency are high. Operational costs are higher than possible alternative markets.
- Market development and implementation time is longer, probably one to two years if constructed to auditable software standards.

The number of generation companies is a matter of choice to some extent. The fewer companies that there are, the more value that investors will put on market share and power. Also, the new companies will need commercial departments, and there are savings here that depend on scale.

If the government wishes to compromise between competitive energy prices and realised value on generation privatisation, then it is in the areas of price setting capability and numbers of competitors that the value is determined. Competition in the proposed generation structure could be aggressive and produce lowest prices if alternative market aspects were considered.

For example, in Germany prices fell by 30% immediately after full retail competition was introduced. The utilities are vertically integrated, but no company was larger than the spare capacity and imports into Germany could supply some 50% of total demand. There is no generation pool, and each company is forced to capture sufficient demand to be able to operate its own generation. The change was simply one of policy to allow full retail competition. The existing structure was unable to defend against this, so the largest companies are trying to merge so that their size exceeds the spare capacity and they can defend their market share.

In England & Wales, the recent market reform will remove the system marginal price pool and introduce a bilateral contracting market, which provides for self-despatch of the contracted volume. This will use some of the features of the Scandinavian and New Zealand markets. Competition in this bilateral contracting market is effectively "pay at bid", which prevents baseload plant earning the SMP by bidding zero, and total costs to customers could consequently be reduced.

Set up costs for a bilateral contract market or power exchange can be small. The management of constraints and demand imbalances could be carried out by the national grid company under a licence condition to minimise costs, which would be regulated accordingly. In England & Wales a transparent balancing market is being established, but this task could be given to the transmission company under an agreement with the government, thus avoiding development costs. This has occurred in Scandinavia.

Supply. Korea is proposing to restructure distribution in the future to create regional distribution companies. This would allow two aspects to develop:

- Retail competition between the supply businesses of each distributor.
- The ability to compare standards of service and thus regulate against benchmarks.

If spare capacity is larger than these distribution supply businesses then it will be possible to force them to defend their regional demand solely by competitive pricing. In practice, strong regulation is required to prevent anti-competitive tactics. By separating distribution from supply it would be possible to encourage other new entrant supply businesses that otherwise would not be able to compete with the distribution companies' databases, billing systems and metering services.

It is not necessary to remove cross-subsidies between commercial and residential sectors. Overall efficiency may be distorted but this will be offset by the social gains. Very poor people and remote connections have to be paid for by a cross-subsidy somewhere in the system.

Overall, this part of the proposed programme of change should deliver the longer term objectives.

Efficiency

The second objective above (to manage present generation over-capacity) requires improved efficiency in all areas of the generation business. Whatever capacity is available should be operated in economic merit order, through whatever competition method is introduced. Commercial economics should encourage the appropriate level of higher priced capacity to be closed and replaced by new capacity. Competition for future construction will deliver this. New build can be commissioned by the private sector, though with over-capacity there may be no need for capacity incentives initially. If generation competition is intense, it is possible to drive prices down to short-run marginal costs that may be too low to attract new investment. If the rate of capacity construction is forecast to be insufficient, then the government may need to commission construction under competitive tender procedures sometime in the future.

Operational efficiency will be incentivised by private ownership and the need to deliver profits to shareholders. The proposals would seem to be adequate here.

The third, fifth and sixth objectives require that standards of service and supply are set through regulation, both for the monopoly transmission and distribution businesses and for the competitive supply sector. Standards and costs can be determined through comparisons and incentives set against benchmarks.

Objective four, to eliminate cross-subsidies, needs careful analysis. There are always sectors of industry that need financial support in some form. This is usually best managed through a government department in the form of taxes and grants, but must be funded from somewhere. If it is to be funded from industry, then cross-subsidy may be appropriate. It is important to try to ring-fence subsidies to avoid distortion of markets or regulated sectors.

Short-term government policies usually result in subsidy and some loss of efficiency and freedom. All markets have numerous examples.

7.2 Comparison with International Experience

Maximising Generation Value for Privatisation

Electricity prices in England & Wales were raised by 7% per year for two consecutive years prior to privatisation to make the generating companies more attractive for privatisation. Over the following 10 years competition reduced wholesale electricity prices by around 30%. However, if prices had not been initially raised it is possible that alternative methods of reducing prices may have produced similar end results. Raising prices extracts more privatisation value but it is paid for by consumers over the following years.

The generating companies were sold with four-year electricity contracts with the distribution businesses. These were renewed at lower volumes and prices four years later. Generation assets have also been sold in Australia (Victoria), Spain,

Colombia and Brazil with contracted output for several years to reduce the risk of market price collapse.

IPP projects were typically contracted for 15 years in the early to mid 1990s, though there has been a tendency in more stable economies recently for stations not to be contracted for their full output if there is a market payment mechanism.

To Improve Business Efficiency in Generation

In the absence of competition, there appears to be a limit to the efficiency gains and cost reductions that can be achieved through re-structuring, re-engineering processes or incentives. Regulated monopolies give the appearance of being "gold-plated", with over-capacity and over-staffing.

Private companies in competitive markets seem to be able to reduce costs several times quicker than companies in regulated environments. The driver is the requirement for continual growth of dividends to shareholders. Market environments tend to impose downward pressure on prices so that profit is gained through efficiency gains and reducing costs.

However, the introduction of a system marginal price pool has more recently been considered by the England & Wales regulator as the cause of inadequate competition between portfolio generators. The combination of such a pool with even six portfolio generators will not produce the most competitive prices.

To Ensure Long-Term Reliable and Inexpensive Electricity

Clearly the aim is an environment that causes prices to reflect costs, plus an appropriate level of profit to encourage long-term reliability. However, although generation plants are initially expected to have a 25–40 year life, one must expect new technology and new fuels to be introduced several times during such a period. The investment may therefore be expected to be profitable for more like 10 years, before facing competition from a competitor with a different cost base. The investment cost recovery should therefore be over this period. Subsequently, the operator then has the option of competing from a position of sunk capital costs and only having to cover marginal fuel costs, or of closing down because costs cannot be recovered. This is the likely situation where gas plant is replacing coal and oil plant, with the added advantages of lower emissions, shorter and lower cost construction, and possibly lower fuel costs.

A credible position for a government is therefore to introduce a competitive market with the objective of driving prices down towards short-run costs, but to retain the possibility of constructing new plant to meet demand growth, if such construction is not being encouraged due to low profit margins. The spare capacity margin can be maintained through competitive tender for construction of new plants. If government-owned, these can be privatised when necessary.

To date, competition for price setting or for despatch has only been introduced in markets that already had significant spare capacity. This naturally provides a period of comfort before finding out if adequate new capacity will result from market incentives. In England & Wales adequate capacity has emerged because new entrant gas generation was priced lower than the wholesale pool price. This probably implies that a capacity payment is unnecessary for this market. In Australia (Victoria), the absence of a capacity payment together with new entrant gas prices being higher than existing lignite prices has caused concern over new

construction. In many US states, new gas entry prices are above the wholesale electricity price and the implication is that prices may rise, as demand is not being satisfied.

The position in Korea would be expected to be determined by the price of new entrant gas-fired generation compared to the prices of existing coal and oil plants.

To Improve Customer Satisfaction with Services

The service areas of most concern are those that interface directly with the public. These are usually the supply activities of customer switching and billing, and the distribution activities of connection, meter installation, reading and repairs. In markets with full retail competition it is possible that all these activities may be open to competition with required service standards. In England & Wales the service standards have all improved and similar reports from Australia support this. The only problem area has been with errors in transferring customer information to new suppliers for billing purposes. This may be because full retail competition is still relatively new.

Similar service standard improvements have been shown in regulated sectors, though usually less innovation is demonstrated.

To Create Distribution and Supply to Deliver Inexpensive Electricity

Regulation has been shown to be successful in all markets in controlling prices. However, it is almost universal that the impact of regulation has been light compared with the effects of competition. The conclusion is that regulation could be more effective in reducing prices.

The US style of regulation encourages "gold-plating", with the system of negotiation to allow costs into the rate base inevitably encouraging over-investment. However, the deregulated environment in New Zealand (where there is no regulator) has not demonstrated price reductions.

The RPI-x formula adopted in England & Wales is unsuitable for recently privatised state companies since x needs to be in excess of 20% initially to compare with efficiencies gained in the competitive generation sector. England & Wales used single figure values for x initially and customers have only accepted recently that regulation is working as it should.

Regulation in Scandinavia has not been successful in controlling distribution charging, with comparative charges varying by over ten fold. However, the wholesale generation market for hydro plant is seen as very competitive.

7.3 Impact of the Proposals

Restructuring KEPCO into Separate Generation Companies

The benefits of restructuring KEPCO are only realisable through competition or privatisation. Both will bring benefits. A higher private share ownership will demand cost efficiencies. Competition will bring this about much more quickly, given present over-capacity. Without this, competitive despatch and price setting is unachievable.

Introduction of a Generation Pool

This has been shown to be an expensive form of market to set up and operate. Set-up costs are estimated at US\$1 billion for California and US\$2 billion for England & Wales. While later implementations may be less costly, the principle of physically realistic representation includes a complexity that is very expensive to develop and operate. In England & Wales it cost US\$8 billion to get to full retail competition.

Alternative forms of competition in generation could be introduced at a fraction of this cost. For example, a power exchange for futures contracts could be operated on the Korean Stock Exchange to provide competition for bilateral contracts. The contract level could be notified to the system operator for self-despatch of plant, with the system operator being required to manage imbalances as a regulated business. The new communications required would be minimal and yet a very competitive market could be developed in a short timescale. Set up costs would be a few tens of millions of US dollars. At six, the number of generators would be sufficient to ensure competitive prices in bilateral contracting, whereas in a system marginal price pool this number would not ensure competitive prices. Under bilateral contracting, KEPCO could trade out of the single buyer role, when it chooses, by allowing others to purchase bilaterally.

An inevitable consequence of generation competition is that any use of indigenous coal and oil for electricity production may be replaced very quickly if gas entry prices are lower. In Europe, coal and oil plants have been forced into closure quickly, with the loss of mining jobs and the associated impact on affected communities. Measures such as retraining, education and improved transport are needed to provide alternative employment. In the case of England & Wales, the Labour government stopped the continued introduction of gas plants because of the potential loss of fuel diversity and to manage the social change process at a slower rate.

Restructuring the Functions of Market and System Operator

Market operation and price determination could be achieved through a futures exchange on the stock exchange, at low cost and within six months of the creation of the generating companies. The system operator could either be independent or part of the national transmission company, and could be regulated with a licence objective of minimising imbalance costs, which would be recovered through regulated transmission charges together with ancillary service costs.

The present proposals should be compared with the above options and debated to determine their relative cost benefits.

Distribution Assets Transferred to Regional Subsidiaries

Transferring distribution assets to regional subsidiaries will permit firmer regulation through comparison of performance. It also provides the electronic systems and databases necessary for full retail competition in the future.

Potential new supply companies may request that distribution and supply are separated so that they can enter the market and compete. This is a point for debate, as is the timing of full retail competition. Germany did not wait for all the expensive systems to be put in place as England & Wales did, yet forced significant price reductions. Other markets, such as Sweden, that forced the

introduction of compulsory metering found that this led to restrictions on customer choice.

Privatising Generation and Regional Distribution Companies

The benefits to be gained from privatisation in terms of reduction of debt and the introduction of incentives throughout these businesses to become more efficient are demonstrated by many international examples. There are few reported cases where standards have fallen as a result of the transfer into private ownership, although there are examples in South America where disconnections have increased as a result of previous under-investment which could not be corrected immediately.

The issue regarding privatisations is the immediate cash gain by the government in return for an expected rate of return on investment, which is dependent on the short-term electricity price forecast. This must be optimised for the country's benefit.

7.4 Conclusions

The government must decide which of the following alternatives it wishes to pursue:

- To maximise the value of KEPCO's generation assets, and introduce a pool which will support electricity prices at levels higher than those achievable with alternative market proposals.
- To aim for lowest competitive prices as quickly as possible, and privatise generation and distribution assets on that basis.

Since Korea is a major exporting country and the government's return from selling its 51% share of KEPCO will be limited, it is recommended that the latter of these should be the preferred objective.

The requirements for the probable success of a competitive market for price setting in generation are given in the table below.

Profile: Republic of Korea	Generation/ Supply	Yes or No
Does the market need lower consumer prices?		Yes
Does it have an attractive investment environment?		Yes
Does it have high prices?	Generation: Supply:	No No
Is there easy access to the grid/market place?	Generation: Supply:	Yes No
Is there excess capacity in generation?		Yes
Is the transmission grid system well interconnected?		Yes
Are there many competitors?	Generation: Supply:	No No
Have other market-specific requirements been satisfied?		Yes

Korea is proposing to privatise its generating assets in six similar fossil companies, with one nuclear company remaining in state ownership. This restructuring in generation, together with excess capacity and a well-connected transmission system, means that this market meets more of the requirements for competition in generation regarding price setting than the others in this study. It is likely that a pool will be as successful here as anywhere else that has implemented such a market.

However, there may be simpler alternative market designs that suit this particular market. Another factor is that prices at present are low and do not allow reasonable rates of return on investment. Competition will help to minimise price rises and also deflect adverse public opinion. It will also encourage cost savings that may allow companies to remain viable at lower prices. The proposed development plan is therefore well conceived. The issue for Korea is whether such a market is as cost effective as alternatives.

The factors to be considered in reducing costs, complexity and timescales are as presented in Chapter 5. The primary factor is what time period is needed for price variation in the market. Most markets have few consumers that require frequent price movements. The vast majority buys electricity on constant rate tariffs and contracts. Most companies have their profitability audited annually, and hence annual contracts are quite suitable. All of this demand could be removed from a short-term market, with more frequent price setting only needed for wholesale purchasers. This could reduce costs and complexity significantly. This is one of the features of a contracting (i.e. long-term) market combined with a short-term balancing and despatch market (e.g. NordPool and the new UK market).

As noted earlier, pools that use system marginal pricing require around 10 companies to create competitive prices and, because of the requirement for frequent metering, are costly to maintain and to change. Software changes can take two years and exceed budgets because of unseen complexity.

It is recommended that Korea segments the market using time periods which are as long as possible. With a good transmission system the market could be optional, to reduce volume passing through it. Contracted generation could be self-despatched to reduce despatch operations to the minimum requirements. If and when this becomes seen as too simple, the time periods could be shortened to the point where new software was needed. Since there are fewer than 10 competitors likely to bid into the market it is advisable not to rely on a system marginal price pool to deliver competitive prices.

A simpler market that is less expensive to develop could still deliver aggressive competition in generation and supply through a contract market in which:

- privatised generation competes for contracts;
- plant self-despatches to contract levels;
- the grid is heavily regulated and despatches plant to meet differences from contracts;
- the size of all supply companies is less than the spare generation capacity;
- distribution companies are heavily regulated.

8. Taiwan, China

8.1 Criteria for Market Design

In summary, the position is that Taiwan requires considerable capacity growth over the next 10 years. It also needs to improve the reliability of supply, while the government is reluctant to raise prices. There is a requirement to attract private funding of investment, and to introduce competition to limit upward price movements. The industry is to be restructured into generation, transmission and distribution. The state utility Taipower will not construct new generation, but new investment projects will have to compete with Taipower to supply end customers.

Efficiency

To meet capacity growth requirements a stable and efficient investment environment is required. It is probably fair to say that this is one of the key areas where significant improvement is needed. Construction projects in the late 1990s have been subjected to several obstacles, including difficulties with:

- achieving an adequate rate of return in competition with that of Taipower (about 6%);
- complicated application and planning approvals;
- the allocation of risk within contracts.

Efficiency in processing project tenders must be improved to enable adequate numbers of project approvals to compete and meet the required growth, given zero generation construction by Taipower.

The balance of project risk between the government/Taipower and private investors must be appropriate to encourage adequate interest in projects. If more foreign investment is to be attracted, contract forms are needed with which the international banking community is comfortable.

Competition

Having improved the business investment environment, more efficient competition for generation projects may be achieved.

Resultant pricing will be influenced by the project risk that investors are requested to manage, and by the pricing structure of Taipower, which will compete to retain customers. If the rate of return for Taipower is limited to around 6% then this may limit the returns achievable by even very efficient new competitors. If returns remain unattractive to new investors, while elsewhere they are higher with more opportunity than can be met by available investment funds, then the government will need to re-appraise its pricing policy.

8.2 Comparison with International Experience

The current objectives for industry reform are:

- To develop an efficient and attractive business environment.
- To restructure the industry into generation, transmission and distribution, with new entrants competing with Taipower to supply customers.
- To privatise Taipower.

To Develop an Efficient and Attractive Business Environment

A multitude of government departments interested in new power projects is a feature of a state-owned electricity industry. Bureaucracy needs to be streamlined with a single authority dealing with applications and approvals.

The discussion in section 4.1 on creating a suitable environment for private investment is particularly relevant here. The conclusion was that investors must be able to determine, to a reasonable probability, what the generation output and price is going to be for their project. In Taiwan, there is no proposal for a generation pool as yet, but the rules for station despatch by an independent operator must be known beforehand if risk is to be calculated and taken by private investors.

Restructuring the Industry

There are no clear examples where restructuring into separate businesses for the purposes of efficiency improvement has turned out to be disadvantageous to the consumer or has failed to reduce costs. However, in principle it should be possible for a vertically integrated monopoly to reduce the resources it uses at the interfaces between the various businesses and to operate with a prime objective of producing electricity at lowest cost to meet required service standards. A centrally planned industry based on a single company should be able to optimise business functions with the benefits of scale.

Unfortunately, state industries are used to delivering different objectives, usually political, and as a result invariably become bureaucratic, inefficient and vastly over-manned, to such an extent that premiums are paid when such industries are privatised due to the numerous commercial opportunities to reduce costs.

If we look back some 30 to 80 years in many cases we see a process where small independent electricity businesses, probably serving a township, were taken into state ownership at some time because:

- financial investment problems arose from rapid growth;
- the benefits of a fully integrated transmission system could not be funded;
- economies of scale in generating plant construction and fuel purchase could not be realised;
- an overall energy policy was required.

The process presently in favour is to complete the circle by breaking up the state monopolies to benefit the consumer. However, this does not help the international expansion plans of such companies and may impede success in winning international orders and exports. Where the development of power systems is at an earlier stage and an integrated system has still to be achieved, there may be benefits from further consolidation, similar to the benefits of state ownership above. However, Taiwan is not in this situation.

The popular method of introducing competition is for the generation and supply sectors to be split into relatively large numbers of competitors, which use the integrated transmission system as the common infrastructure over which to compete. One of the requirements for adequate competition is an over-supply of the product. This is not the case in Taiwan, and therefore competition in the operational businesses is premature, whereas in the process of constructing capacity it is preferable.

Competition in the transmission and distribution businesses is not in favour worldwide, though new line construction could in principle be independent.

The proposed restructuring in Taiwan into generation, transmission and distribution will allow the individual costs of wholesale energy and transmission charges to be identified separately and used independently by new entrants. In addition, this will allow the costs of these businesses to become more transparent and therefore some improvement in efficiency within the operation of Taipower should result. Restructuring alone does not result in the efficiency gains produced through competition, but 25–35% improvements have been seen in companies preparing for privatisation, such as in Australia and England & Wales.

Because Taipower will continue as a single entity that will dominate the industry, it is advisable to set up independent functions such as regulator, grid operator, ancillary services procurer, and connection applications. The proposals to restructure and set up some of the necessary independent activities are very sensible.

Privatisation of Taipower

It is proposed to privatise Taipower as a wholly integrated company, albeit with greater separation between generation, transmission and distribution. Putting Taipower into private ownership will result in further efficiency gains as shareholders pursue profits. If prices are regulated and limited, Taipower's strategy can only be to reduce costs. As a monopoly, regulation will continue and it is possible that the government may consider that regulation of a private monopoly is preferable to waiting a few years for the capacity margin to become sufficient and then splitting Taipower to produce competing companies. Although regulators in the USA and the UK have been successful in forcing companies to sell off generation assets, the required competition laws were there to support this.

Although there would be some benefit in Taiwan to realising privatisation revenues sooner to reinvest elsewhere, similar privatisations elsewhere of state-owned industries as single entities have tended to prevent the onset of competition for many years. For example, in the UK gas and telecommunications industries it took around 10 years for competition to emerge following privatisation, and this had to be introduced with further legislative changes. Once in private ownership, the strategy of a monopoly will be to resist competition where possible.

The overall benefit of privatising Taipower as a whole is unclear. It would seem to be the maximisation of asset value at the expense of a potential delay in introducing competition.

8.3 Impact of the Proposals

To Develop an Efficient and Attractive Business Environment

The desired impact is that more than sufficient investment schemes are put forward to allow choice, which will hopefully drive prices to acceptable levels and avoid price rises. Failure to attract and approve sufficient projects will seriously affect the economy of Taiwan.

Streamlining processes at the various levels of government, all of which will believe that they are fulfilling worthwhile functions, is always a difficult task. In state industries, it is usually solved by selling the problem to another owner. The new owner will deal with the restructuring and re-engineering in order to benefit

through the resultant cost savings. In government offices this solution is not available, yet the same outcome is needed.

Restructuring the Industry

Industry restructuring leads to significant changes in responsibilities and usually some manpower reduction, possibly around 25%. However, this relatively small improvement in efficiency is not the prime objective. The main aim is to set up separately managed industry sectors in which new entrants can compete, in particular with the Taipower generation and supply businesses.

Because of the required large increase in generation capacity in Taiwan, it is unlikely that significant efficiency improvements will result within Taipower until there is competitive pressure from new entrants to win significant numbers of customers and demand from Taipower. This could cause Taipower to reduce costs to defend generation output, but probably it would probably not compete aggressively until the company was privatised.

Privatisation of Taipower

The proposal is to privatise Taipower as a whole, but with distribution restructured into regional subsidiaries.

This will probably realise the maximum cash value for the government at an early stage, so that it may be re-invested elsewhere. Competitive pressure on Taipower to produce significant changes will be light, probably for 10 years or so. This will leave government and regulatory departments to manage the impact of a very dominant company in the industry. The future impact will depend on the strength of the powers that the government and regulator hold over Taipower. Elsewhere, the resultant changes and improvements in efficiency have been slow under such circumstances.

8.4 Conclusions

Taiwan has not commissioned sufficient new generating capacity to meet growing demand. Difficulties exist in most aspects of winning approval for new stations, and the investment environment must be a priority for improvement. Sufficient projects are put forward initially, but more competition if possible at the proposal stage, would encourage costs to be reduced.

Retail prices are low, and with current levels of utility efficiency this causes low rates of return. Competition and restructuring are seen as the solution, allowing prices to move freely without the government having to raise them and risk adverse publicity.

In summary, the short-term objectives for successful liberalisation are:

- To develop an investment environment that is efficient in dealing with applications and attracts adequate generation construction.
- To restructuring the industry into the different businesses.
- To privatise Taipower to improve efficiency and raise funds (although competition in the future would be greater if Taipower were split up).

This last point equates to “cash now” versus “less cash later, but a more competitive industry”.

The requirements for the probable success of a competitive market for price setting in generation are given in the table below.

In the next few years Taiwan will not have the necessary requirements for competition of excess generation capacity, a robust transmission system and many competitors. Consequently, the government should try to meet its objectives for competitive despatch using long-term cost information which is registered and audited on a seasonal frequency. Only availability information is required frequently.

The restructuring proposals are sensible but competition for despatch is unlikely to be seen as fair by new independent generators if Taipower remains as a large single company. For this reason there is no justification for the introduction of anything other than simple competition for despatch. Apart from despatch there seems no point at this stage in using short time periods for price setting.

Improving the business development environment must be the prime objective, but the question remains of whether this can be done quickly enough to avoid delaying the required construction programme.

Profile: Taiwan, China	Generation/ Supply	Yes or No
Does the market need lower consumer prices?		Yes
Does it have an attractive investment environment?		No
Does it have high prices?	Generation: Supply:	No No
Is there easy access to the grid/market place?	Generation: Supply:	No No
Is there excess capacity in generation?		No
Is the transmission grid system well interconnected?		No
Are there many competitors?	Generation: Supply:	No No
Have other market-specific requirements been satisfied?		No

9. Thailand

9.1 Criteria for Market Design

The state of the electricity industry in Thailand is healthy and standards are good. Prices are reasonable and there is sufficient fuel availability and plant capacity. The industry is developing steadily in a planned manner towards liberalisation, by which it is intended to increase the efficiency of the utilities, reduce government involvement in their operation, and to increase competition.

Plans for regional decentralisation of utilities into corporatised subsidiaries and for privatising the Provincial Electricity Authority and the Electricity Generating Authority of Thailand were approved in principle in the mid 1990s. Objectives for further development of the industry, to deliver improved efficiency and service standards, should be:

- To restructure the industry and achieve high privatisation values (privatisation is planned after 2004 when market design will have been clarified).
- To continue stable inward investment.
- To increase competition in the construction process and in the operation of generating plants.
- To decide on mutually beneficial ways of developing cross-border power transfers with neighbouring countries.

Before 2003 wheeling access will be introduced for private power producers to sell directly to customers. Pool competition in generation, with an independent system operator to manage the market, will be considered after 2003, together with the introduction of retail competition with transmission access and tariffs overseen by a national regulator. Beyond this, the necessary legislation and regulatory powers will need to be approved to introduce competition in generation, and retail access and competition.

For the former, market models need to be appraised and a suitable model chosen to develop the future structure of generation. For the latter, customer service standards, particularly in retail, and benchmarks for regulating the necessary charges and investments must be decided.

9.2 Conclusions

In summary, the requirement is to set clear objectives and targets for the master plan regarding:

- regional decentralisation;
- reduction in government investment;
- access to consumers for IPPs;
- consideration of wholesale and retail competition;
- restructuring and privatisation;
- understanding the effect of the type of competitive market on stranded costs.

The requirements for the probable success of a competitive market for price setting in generation are given in the table below.

Profile: Thailand	Generation/ Supply	Yes or No
Does the market need lower consumer prices?		Yes
Does it have an attractive investment environment?		Yes
Does it have high prices?	Generation: Supply:	Yes No
Is there easy access to the grid/market place?	Generation: Supply:	Yes No
Is there excess capacity in generation?		Yes
Is the transmission grid system well interconnected?		Yes
Are there many competitors?	Generation: Supply:	No No
Have other market-specific requirements been satisfied?		Yes

Thailand has good conditions for future competition in generation and supply. The plan for restructuring and prospective privatisation after 2004 seems reasonable. With excess capacity in generation and a well-connected transmission grid, the fundamental requirements for competition in generation exist. The final requirement is for sufficient companies to create competition.

Future proposals consider a pool-type market. If this uses system marginal pricing then competition will not emerge until around 10 companies are bidding to operate. Since fewer than this are expected, Thailand should consider a simpler market using contract competition as much as possible, since this requires fewer competitors. The recommendation would be to investigate markets which are less complex and less costly to set up and operate than a compulsory pool.

APPENDIX 4. DATA TABLES FOR SELECTED ELECTRICITY MARKETS

Data for the following Asia-Pacific electricity markets were collected in *tabular* form and are included in this Appendix for reference:

- Hong Kong, China
- Indonesia
- Philippines
- Republic of Korea
- Taiwan, China
- Thailand

HONG KONG ELECTRICITY INDUSTRY PROFILE

Year	1994	1995	1996	1997	1998
Total Demand (TWh) ¹	33	33	35	36	39
Imports (+) Exports (-) (TWh) ²	5	5	7	7	8
Total Sales (US\$bn)	2.6	2.9	3.3	3.5	4.0
Peak Demand (GW)	6.8	6.7	7.1	7.3	7.6
Peak Imports (GW)	-	-	-	-	-
Capacity Committed (GW) ³	10.3	9.8	11.1	11.3	11.6
Investment Needed (US\$bn)	1.2	1.4	1.1	0.8	0.7

ELECTRICITY PRICES (HK CENTS PER KWH)

Year		1994	1995	1996	1997	1998
All demand types	Nominal	68.8	75.3	80.3	85.1	89.1
	Real	68.8	69.3	69.7	69.8	71.3

INDUSTRY STRUCTURE AT END 1998

Generation	Total	
	GW	TWh
Hydro (pumped storage) ⁴	0.6	0
Conventional Thermal	7.7	21
Nuclear	1.4	9
Gas	1.6	9
Other	-	-
Total	11.6	39

Distribution	Total
Customers (m)	2.3
Energy (TWh)	35
Revenue (US\$bn)	4.0

1. Excludes demand from China
2. Imports from China less exports to China (CLP Power only)
3. Includes capacity available in China
4. Located in China

INDONESIA ELECTRICITY INDUSTRY PROFILE

Year	1994	1995	1996	1997	1998
Total Demand (TWh)	43.061	49.789	56.932	64.311	65.261
Imports (+) Exports (-) (TWh)	-	-	-	-	-
Total Sales (US\$bn)	0.95	1.16	1.34	1.55	0.197
Peak Demand (GW)	6.734	7.773	8.822	10.016	9.876
Peak Imports (GW)	-	-	-	-	-
Capacity Committed (GW)	14.327	14.986	16.109	18.946	20.581
Investment Needed (US\$bn)	-	-	-	-	-

ELECTRICITY PRICES (RUPIAH PER KWH)

Year		1994	1995	1996	1997	1998
Industrial	Nominal	137.75	144.79	146.16	149.70	201.01
Commercial	Nominal	255.49	264.00	266.04	270.35	305.83
Domestic	Nominal	159.46	169.35	171.05	174.08	227.68

INDUSTRY STRUCTURE AT END 1998

Generation	Total	
	GW	TWh
Hydro	3.006	9.649
Conventional Thermal	6.770	30.512
Gas	1.347	3.836
Other	2.895	7.923
Total	14.018	51.920

PHILIPPINES ELECTRICITY INDUSTRY PROFILE

Year	1994	1995	1996	1997	1998
Total Demand (TWh)	30.620	33.296	35.613	38.724	39.906
Imports (+) Exports (-) (TWh)	-	-	-	-	-
Total Sales (US\$bn)	1.943	2.018	2.447	*2.024	*2.271
Peak Demand (GW)	4.814	5.328	5.781	6.350	6.421
Peak Imports (GW)	-	-	-	-	-
Capacity Committed (GW)	9.067	9.563	10.489	11.000	11.817
Investment Needed (US\$bn)	1.353	1.306	1.663	1.675	2.051

* On account of Peso devaluation from PHP26 to 39 to US\$1

ELECTRICITY PRICES (PESO PER KWH)

Year		1994	1995	1996	1997	1998
Industrial	Nominal	1.6202	1.6830	1.8127	1.9871	2.3619
	Real	1.6202	1.6372	1.6615	1.6712	1.8730
Domestic	Nominal	1.8186	1.8065	1.9958	2.1885	2.5681
	Real	1.8186	1.7573	1.8293	1.8406	2.0366

INDUSTRY STRUCTURE AT END 1998

Generation	Total		NPC		IPPs	
	GW	TWh	GW	TWh	GW	TWh
Hydro	2.276	5.051	2.235	4.602	0.041	0.449
Oil	3.986	16.007	2.611	5.136	1.375	10.871
Coal	2.080	9.385	1.305	4.483	0.775	4.902
Geothermal	1.901	8.902	1.214	5.889	0.687	3.013
Other	1.595	0.561	1.185	0.160	0.410	0.401
Total	11.838	39.906	8.550	20.270	3.288	19.636

Distribution	Total	A	B	C	Others
Customers (m)	8.451	3.315	0.220	0.178	4.738
Energy (TWh)	28.431	20.306	1.061	0.846	6.218
Revenue (US\$bn)	2.880	2.092	0.102	0.061	0.625

A – Manila Electric Co; B – Visayas Electric Co; C – Davao Light & Power

REPUBLIC OF KOREA ELECTRICITY INDUSTRY PROFILE

Year	1994	1995	1996	1997	1998
Total Demand (TWh)	146.54	163.27	182.47	200.78	193.47
Imports (+) Exports (-) (TWh)	-	-	-	-	-
Total Sales (US\$bn)	9.26	9.99	10.99	11.99	11.88
Peak Demand (GW)	26.70	29.88	32.28	35.85	33.00
Peak Imports (GW)	-	-	-	-	-
Capacity Committed (GW)	28.77	31.79	35.72	40.53	43.26
Investment Needed (US\$bn)	4.68	6.01	6.56	8.71	7.01

ELECTRICITY PRICES (WON PER KWH)

Year		1994	1995	1996	1997	1998
Industrial	Nominal	46.14	47.14	48.37	49.86	55.01
	Real	46.14	45.11	44.13	43.54	44.69
Commercial	Nominal	86.92	89.00	90.32	93.19	104.16
	Real	86.92	85.17	82.40	81.37	84.62
Domestic	Nominal	85.95	86.47	88.95	92.05	96.60
	Real	85.95	82.75	81.15	80.38	78.47

INDUSTRY STRUCTURE AT END 1998

Generation	Total		KEPCO		Other	
	GW	TWh	GW	TWh	GW	TWh
Hydro	3.154	6.099	2.136	3.625	1.018	2.474
Conventional Thermal	18.674	89.617	18.674	89.617	-	-
Nuclear	12.716	89.689	12.716	89.689	-	-
Gas	10.785	26.505	9.285	15.026	1.500	2.625
Co-generation	-	-	-	8.854	-	3.390
Total	45.329	215.300	42.811	206.811	2.518	8.489

Distribution	Total	KEPCO
Customers (m)	14.102	14.102
Energy (TWh)	193.472	193.472
Revenue (US\$bn)	-	-

TAIWAN ELECTRICITY INDUSTRY PROFILE

Note: Data are for Taipower only

Year	1994	1995	1996	1997	1998
Total Demand (TWh)	98.56	105.37	111.14	118.30	128.13
Imports (+) Exports (-) (TWh)	-	-	-	-	-
Total Sales (US\$bn)*	-	226.386	238.870	254.564	268.368
Peak Demand (GW)	18.61	19.93	21.76	22.23	23.83
Peak Imports (GW)	-	-	-	-	-
Capacity Committed (GW)	20.98	21.90	23.76	25.74	26.68
Investment Needed (US\$bn)*	93.505	95.526	107.266	97.891	102.993
Exchange Rate NT\$/US\$ end June	-	25.801	27.500	27.882	34.487
Average Exchange Rate	26.50	26.50	27.46	28.95	32.22

ELECTRICITY PRICES (NT\$ PER KWH)

Year		1994	1995	1996	1997	1998
Industrial	Nominal	2.0149	2.0010	1.9969	1.9606	1.9311
Commercial	Nominal	2.9293	2.9360	2.9291	2.9291	2.9352
Domestic	Nominal	2.3719	2.3946	2.4190	2.4190	2.4578
Wholesale Price Index		94.07	101.01	100.00	99.54	100.14
Consumer Price Index		93.58	97.02	100.00	100.90	102.60

INDUSTRY STRUCTURE AT END 1998

Generation	Total		Taipower		Other	
	GW	TWh	GW	TWh	GW	TWh
Hydro	4.430	10.584	4.172	9.575	0.258	1.009
Conventional Thermal	16.264	80.185	13.183	79.937	3.081	0.248
Nuclear	5.144	35.408	5.144	35.408	-	-
Gas	3.930	13.737	3.930	13.737	-	-
Other	2.865	15.791	-	-	2.865	15.791
Total	32.633	155.704	26.425	138.656	5.954	13.748

Distribution	Taipower
Customers (million)	10.100508
Energy (TWh)	128.1298
Revenue (US\$bn)*	7.782

* Figures are fiscal year basis, e.g. fiscal year 1995 means from 1 July 1994 to 30 June 1995

THAILAND ELECTRICITY INDUSTRY PROFILE

Year	1994	1995	1996	1997	1998
Total Demand (TWh)	63.64	72.78	79.45	85.90	85.60
Imports (+) Exports (-) (TWh)	0.75	0.67	0.64	0.71	1.27
Total Sales (US\$bn)	3.04	3.61	3.93	3.04	2.90
Peak Demand* (GW)	11.42	12.99	14.26	15.47	15.53
Peak Imports (GW)	-	0.07	0.04	0.08	0.24
Capacity Committed (GW)	12.97	14.69	16.14	16.98	18.18
Investment Needed (US\$bn)	1.10	1.22	1.12	0.93	1.21
Exchange Rate THB/US\$ end Sept.	25.02	25.12	25.47	36.60	39.47

* Sum of maximum demand

ELECTRICITY PRICES (THAI BAHT PER KWH)

Year		1994	1995	1996	1997	1998
Residential	Nominal	1.67	1.80	1.88	1.98	2.21
	Real	1.67	1.70	1.68	1.68	1.73
Small General (<30 kW)	Nominal	2.19	2.31	2.38	2.47	2.69
	Real	2.19	2.18	2.13	2.09	2.10
Medium General (30-2000 kW)	Nominal	1.67	1.77	1.84	1.97	2.25
	Real	1.67	1.67	1.64	1.67	1.76
Large General (>2000 kW)	Nominal	1.46	1.55	1.61	1.69	1.91
	Real	1.46	1.47	1.44	1.43	1.49
Specific Business (>30 kW)	Nominal	1.68	1.78	1.86	1.96	2.19
	Real	1.68	1.68	1.66	1.66	1.71
Government & Non-profit	Nominal	1.63	1.73	1.79	1.87	2.11
	Real	1.63	1.64	1.60	1.58	1.65
Agricultural Pumping	Nominal	1.12	1.22	1.30	1.40	1.63
	Real	1.12	1.15	1.16	1.18	1.28

(continued on next page)

INDUSTRY STRUCTURE AT END 1998

Generation	Total		EGAT		IPPs		Others	
	GW	TWh	GW	TWh	GW	TWh	GW	TWh
Hydro	3.50	7.26	2.87	3.43	-	-	0.32	1.93
Conventional Thermal	9.92	58.41	6.52	38.37	2.06	13.95	1.34	6.09
Combined Cycle	5.07	25.38	5.07	25.38	-	-	-	-
Gas Turbine	0.89	1.25	0.89	1.25	-	-	-	-
Other	0.01	0.01	0.01	0.01	-	-	-	-
Total	19.39	92.31	15.36	68.44	2.06	13.95	1.66	8.02

Distribution	Total	MEA	PEA	Direct	Others
Customers (m)	12.63	2.05	10.58	0.000008	0.000008
Energy (TWh)	80.85	31.12	48.00	1.20	0.52
Revenue (US\$bn)	4.41	1.80	2.54	2.03	0.79

